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PROPOSED PROGRAM

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5-Year Outer Continental Shelf Oil and Gas Leasing Program for January 1987 - December 1991

Detailed Decision Documents

FEBRUARY 1986

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PROPOSED PROGRAM

5-YEAR OUTER CONTINENTAL SHELF OIL AND GAS LEASING PROGRAM FOR JANUARY 1987 - DECEMBER 1991

UNITED STATES DEPARTMENT OF THE INTERIOR

MINERALS MANAGEMENT SERVICE

DETAILED DECISION DOCUMENTS
FEBRUARY 1986

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Decision Memorandum to the Secretary of the Interior: Adoption of a Proposed 5-Year Outer Continental Shelf Oil and Gas Leasing Program for 1987-1991 (dated October 15, 1985), including:

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Attachment 2--Three Alternative Leasing Schedules for the Proposed Program;

Attachment 3--Maps of the Outer Continental Shelf Planning Areas; and

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United States Department of the Interior

OFFICE OF THE SECRETARY
WASHINGTON, D.C. 20240

OCT 15 1985

MEMORANDUM

TO: The Secretary

FROM: Assistant Secretary - Land and Minerals Management

SUBJECT SUMMARY: Adoption of a Proposed 5-Year Outer Continental Shelf (OCS) Oil and Gas Leasing Program for 1987-1991--Request for Secretarial Action

DISCUSSION

Section 18 of the OCS Lands Act, as amended, requires you to prepare and maintain an oil and gas leasing program for the United States OCS. It also requires that "The leasing program shall consist of a schedule of proposed lease sales indicating, as precisely as possible, the size, timing, and location of leasing activity which [the Secretary] determines will best meet national energy needs for the five-year period following its approval . . . ."

The Minerals Management Service (MMS) has reviewed comments on the Draft Proposed Program (DPP) which you issued in March 1985, revised the analysis, and restructured the options for the Proposed 5-Year OCS Oil and Gas Leasing Program for the period January 1987 to December 1991. Your selection of a Proposed Program at this time is necessary to provide sufficient overlap with the current schedule and to allow advance planning for early sales in the new schedule to begin so that a hiatus in leasing can be avoided.

It is important to keep in mind the preliminary nature of this stage of the program development and approval process. The Proposed Program and the Secretarial Issue Document (SID) are scheduled to be forwarded in December 1985 to the Governor of each affected State, the Attorney General, and appropriate Federal Agencies for a 90-day review and comment period. Comments will be solicited from potential oil and gas producers and the interested public by means of a Federal Register Notice announcing the Proposed Program. Copies also will be sent to the Congress. A draft environmental impact statement (EIS), currently in preparation, will be issued shortly after the Proposed Program. The draft EIS will use as the proposed Federal action your decision on the Proposed Program. The Proposed Program and draft EIS will be the focus of an early 1986 meeting of the OCS Policy Committee. Following the 90-day comment period for the Proposed Program, the SID will be revised once more to provide the basis for your decisions on the Proposed Final Program in late 1986 or early 1987. Final approval of the 5-year leasing program can be made by you after a 60-day waiting period before Congress and the President.

Prepared by: Paul R. Stang Ext.: 343-1072

Formulation of the Proposed Program requires your selection of the following:

- a configuration of planning areas (including possible deletion or other treatment of subareas);
- a leasing schedule;
- a presale process leading to decisions on the size of individual lease sales; and
- provisions to assure receipt of fair market value.

Attached for your use in making these selections are:

- a decision sheet (Attachment 1);
- three alternative leasing schedules (Attachment 2);
- maps of the proposed OCS planning areas (Attachment 3);
- the SID and Appendices on the Proposed Program (Attachment 4); and
- a description of subareas which commenters have suggested for deferral and potential Department of Defense (DOD) and National Aeronautics and Space Administration (NASA) exclusive use areas (Attachment 5).

The SID includes an analysis of specific factors which section 18 requires you to consider in formulating a 5-year leasing program. These factors, most of which are analyzed and arrayed by OCS planning area in the SID, include:

- geographical, geological, and ecological characteristics;
- equitable sharing of developmental benefits and environmental risks;
- relative needs of regional and national energy markets;
- other uses of the sea and seabed;
- interest of potential oil and gas producers;
- laws, goals, and policies of affected States;
- relative environmental sensitivity and marine productivity; and
- environmental and predictive information.

You are required to consider these factors in the selection of the timing and location of leasing "so as to obtain a proper balance between the potential for environmental damage, the potential for the discovery of oil and gas, and the potential for adverse impacts on the coastal zone." Furthermore, the leasing program must be prepared and maintained in a manner consistent with the principle that leasing activities be conducted to assure receipt of fair market value for the lands leased and the rights conveyed.

THE MARCH 1985 DECISION ON THE DPP

As a point of reference, the DPP, which you issued in March 1985, slows the pace of leasing in comparison with the current program. It contains the following provisions:

- sales in 22 planning areas;
- 33 standard sales, 5 frontier exploration sales, and 5 supplemental sales;
- no sales in St. Matthew-Hall, Aleutian Arc, Aleutian Basin, and Bowers Basin;
- a provision to accelerate sales in eight areas of higher value and/or higher interest (but not so as to increase the total number of sales in any planning area in the approved program);

- a presale process which results in focusing on promising acreage; and
- maintenance of current procedures for assuring the receipt of fair market value and a review of the question of whether the minimum bid level would be changed either in general or on a variable basis for different planning areas.

THE VALUE OF FLEXIBILITY

In 1981-82, when the analysis and decision process for the current program were underway, many analysts predicted that the price of oil and gas would continue to climb. Estimates of world oil prices reaching $60 (1982 dollars) per barrel or more by the end of the century were common. However, such price escalation has not yet occurred, and over the last 2 years, there has been a downward price trend. When the analysis was initiated, the actual price of oil was $29 per barrel (average free on board U.S. import price weighted by import volume), down from $34 in 1982. It has since dropped to about $26 as of August 1985. It is not clear whether this short-term downward trend will become a long-term trend. What is clear is that there is a far greater sense of uncertainty in perceptions and a far lower range of projections of future energy prices now than existed in 1981-82. The debate then was whether real long-term price increases would be 1, 2, 3, or more percent per year. The debate now ranges from projections of moderate near-term increases to forecasts of substantial near-term declines in oil prices if current trends in the world oil market continue. However, currently adequate oil supplies and low oil prices can obscure the need to take steps now to find adequate oil supplies through the rest of this century and the beginning of the next--for that is the period of production from areas leased in the new 5-year program.

Current prices and expectations about future oil and gas prices strongly affect the number of OCS tracts for which firms submit bids and the amount of their bids. Accordingly, the amount of acreage that will actually be leased by the program you choose will vary substantially depending upon events in the world oil market and companies' perception of how those events will influence future prices.

In formulating this leasing program, it is important to recognize that substantial economic and national security benefits may be realized from production of oil and gas found on OCS acreage that is leased during the 5-year term of the program. Such leases will come from acreage that is unleased as of 1987 or from leased acreage which is surrendered and leased again. These potential benefits make the OCS program one of the most beneficial of the Government's economic programs. In addition, the potential benefits would be realized largely in the form of Federal revenues which will help reduce future Government deficits.

The 5-year leasing program can influence the benefits realized because it controls the availability of investment opportunities in exploratory drilling on unleased OCS acreage, and thus in substantial measure, the ability of firms to adjust their OCS activities to emerging conditions in the world oil market. By determining the location and timing of OCS sales for the 1987-91 period, your final approval of a leasing program will set the bounds within which firms investing in exploration on the OCS will be able to make such adjustments during the 5-year period and up to a decade thereafter. If you choose a leasing program

with relatively small sales at less frequent intervals in fewer areas, the range of possible investments will be more limited. Such a choice may permit investors in OCS exploration to respond adequately to relatively low and stable world oil prices, but might not permit expanded leasing and exploration in response to higher price expectations. On the other hand, if you choose a leasing program with relatively large sales at more frequent intervals in more areas, the range of possible investments may be greater. Thus, while a more extensive leasing program could yield the same level of investment as a more restrictive program if lower prices are expected, a restrictive program would not allow substantial expansion in leasing and subsequent exploration if world oil price expectations were to rise more than anticipated.

Selecting a leasing program flexible enough to allow for necessary adjustments is also important given the structure of the OCS Lands Act. If a 5-year program is approved with relatively frequent sales in a relatively large number of planning areas in anticipation of the likelihood of high future energy prices, and if price expectations then wane, the program would be flexible enough to adjust without reinitiating the 2-year approval process required by section 18. On the other hand, if a scaled-down 5-year leasing program is approved and future energy prices appear to be rising faster than anticipated, the program cannot be scaled up without reinitiating the 2-year approval process. The cost to the Nation of such delay could be substantial. Flexibility in the program also needs to be balanced with stability in the program to allow affected parties and the oil and gas industry to plan efficiently and maintain public confidence in the program.

Public opinion on the Proposed Program may be strongly influenced by the scope you select. A more extensive program with opportunities for acceleration may be criticized by some States, environmental groups, and coastal residents, but would be well received by industry. These positions would likely be switched if a more limited program is selected. These opinions, already reflected to some degree in comments on the DPP and summarized later in this memorandum, also should be considered in deciding the appropriate level and frequency of leasing and the degree of flexibility built into the program.

SECTION 18 ANALYSIS

Both the June 1980 and the July 1982 5-year programs were challenged in the U.S. Court of Appeals for the District of Columbia Circuit. The court found that the section 18 analysis performed for the 1980 program did not fully comply with the statute, but that the 1982 program formulation fully complied with the statute and the guidance the court had set forth in its opinion on the 1980 program. The analysis undertaken for the DPP and refined for the Proposed Program is very similar to, but more extensive than, that conducted for the July 1982 program. For instance, estimates have been made of oil and gas resources, economic benefits to the Nation and environmental effects for the various planning areas to show more specifically how the potential benefits and costs can be affected by changes in the world oil market. Economic benefits were projected for a variation in oil prices from the actual 1984 price of $29 per barrel to an assumed low price of $19 per barrel, in conjunction with a real oil price increase of 1 percent and an 8 percent discount rate. These projections were supplemented with sensitivity analyses using real oil price increases of 0 and 2 percent per year, and a 6 percent discount rate.

As initially reflected in the DPP and confirmed in the attached refined analysis, both the per barrel and total estimated economic benefits for unleased and undiscovered resources are lower than those of the 1982 analysis. These reductions were caused in part by leasing since 1982 and projected leasing in the late 1985 to 1986 period, as well as the decline in oil price expectations. Declines in the resource estimates also contributed, especially in the Alaskan and Atlantic planning areas where disappointing exploration results were experienced. Most estimates of potential social costs (environmental and other costs not normally included in the cost of OCS operations) which might result from production are also lower than those of the 1982 analysis, but the drop for most planning areas is much more substantial than the drop in economic benefit. This is due not only to a reduction in projected leasable acreage and an improved safety record, but also to a revision in the assumptions used, which in retrospect greatly overstated potential social cost in the 1982 analysis.

Estimated net social value, the difference between estimated economic benefits and estimated social costs, is so large in every planning area that the social costs would have to be many times larger than estimated in order to reduce the expected net social value to zero. Table 12.1 in the SID shows that economic benefits are more than 17 times larger than the estimated social costs in one planning area and at least 85 times larger for all other planning areas for which there are estimated resources.

LOCATION, TIMING, AND SIZE

The following discussion of comments on and options for location, timing, and size of leasing incorporates the factors which you are required to consider under section 18 in formulation of the new 5-year program.

Nearly 350 comments were received in response to the release of the DPP in March 1985. A brief summary of comments appears in the Introduction of the SID, and a detailed summary appears in Appendix B.

Location Comments

Many Governors requested that specific areas be deleted from the leasing program. Alaska requested deletion of tracts near Unimak Pass, the Pribilof Islands, Yukon Delta, and Point Barrow and requested that no sales be held in the North Aleutian Basin until 1994. Delaware expressed concern about leasing in submarine canyonheads and within 12 miles of the State's territorial waters. Florida recommended permanent removal of the NASA/DOD Flight Clearance Zone from the South Atlantic Planning Area and requested deferral of a portion of the Eastern Gulf of Mexico Region.

Maine and Massachusetts requested exclusion of the Gulf of Maine. Massachusetts also requested the exclusion of Georges Bank, submarine canyons, and areas encompassed by the 400-meter isobath. Maryland recommended that areas off its coast be considered for tract selection. New Jersey and Virginia recommended deletion of areas within 50 miles of their coasts. New Jersey also expressed concern about leasing within biologically sensitive submarine canyon systems.

North Carolina requested deferral of areas shoreward of the 200-meter isobath off the State, a buffer zone around the Monitor Marine Sanctuary, the Ten Fathom Ledge, and Big Rock shelf areas. Oregon requested deletion of the outer portion (between 125° and 128° W. longitude) of the Washington-Oregon planning area, as well as Heceta, Stonewall, and Perpetua Banks.

Petroleum industry commenters generally opposed deletion of subareas from planning areas. One company did recommend that DOD activity areas receive special consideration. Two industry commenters recommended that certain leasing locations, such as frontier and deepwater areas, be given special treatment (such as longer lease terms, lower minimum bid, etc.) based on consideration of drilling results, economics, technology, and needs.

Several other commenters made deletion requests and additional comments pertaining to location of leasing.

Timing Comments

The Governors made several requests and recommendations concerning the timing of leasing. Alabama stated that more sales should be scheduled outside the Gulf of Mexico planning areas. Louisiana commented that leasing annually in the Gulf of Mexico and triennially in other planning areas does not provide for equitable sharing of leasing among various regions. Massachusetts requested that only one North Atlantic sale be scheduled in the next 5-year program. New Jersey recommended deceleration of the sale schedule for the Mid-Atlantic and North Atlantic planning areas. Oregon requested that enough time be provided for completing environmental studies prior to holding a sale in the Washington-Oregon planning area.

Several industry commenters stated a preference for biennial leasing in most planning areas outside the Gulf of Mexico.

Options for Location and Timing

Determining the location and timing of leasing requires decisions on the configuration of planning areas, the selection of planning areas to be included in the schedule, the order in which they will be offered for lease, and the frequency of sales within planning areas.

Since the March 1985 request for public comments (reproduced in Appendix M of the SID) a few minor modifications to planning area boundaries have been made as recommended by the Department of State. You are requested to: (1) confirm the configuration of planning areas on which the section 18 analysis has been performed; (2) select any or all additional planning area changes; (3) determine which subareas will be deferred from the 5-year program or flagged for special treatment during the presale process; and (4) decide whether the seaward boundary of the Northern California and Washington-Oregon planning areas should be revised to coincide with the limits of the Exclusive Economic Zone.

The quantitative analyses in the SID provide part of the basis you should use to determine in which planning areas sales should be scheduled. If the estimated benefits of oil and gas production in an area exceed the estimated costs, the area should be considered further for inclusion in the 5-year program. The net social value calculations show this to be the case for each of the planning areas for which there are estimated resources. Similarly, with respect to timing, the net social value calculations are divided into groups which can be used as a guide in deciding the frequency of sales in a particular planning area. In general, the higher the net social value group, the more frequently sales should be scheduled in that area, subject to the qualitative considerations discussed below.

It should be noted that deferral of one or more subareas within a planning area could move a planning area to a higher or lower net social value group and thus, could have an effect on decisions on the frequency of leasing. Any planning area affected by subarea deferrals will be reanalyzed for the Proposed Final Program so you can see what that effect would be. If subarea deletions are to be made, it would be preferable, given the analytical requirements of section 18, to select them now and/or early in the process of developing the Proposed Final Program. This will allow completion of the required analyses before the decision on the Proposed Final Program. The description of candidates for subarea deferral recommended by commenters is presented in Attachment 5.

In keeping with your statements this past summer, one of the specific options presented defers eight subareas off California: the area offshore the Pt. Reyes Wilderness; Pt. Reyes/Farallon Islands National Marine Sanctuary; the area in the immediate vicinity of Cordell Bank; the area offshore San Francisco Bay; the areas offshore Monterey Bay; the areas offshore Big Sur; Santa Barbara Federal Ecological Preserve and Buffer Zone; and Channel Islands National Marine Sanctuary.

By using the results of the section 18 quantitative analysis and industry interest rankings (see Table 13.2 of SID), a base schedule (Option 2-a) and five amendments (Option 2-b to 2-f) have been developed for your consideration. The combination of Options 2-a, 2-d, 2-e-i, and 2-f comprise a schedule nearly identical to that which you selected for the DPP. While many other combinations are possible, three schedules (see Attachment 2) showing all sales in Options 2-a, 2-d, and the combination of 2-a and 2-e have been developed. The other Options, 2-b, 2-c, 2-f, and combinations thereof, are relatively easy to envision and thus are not shown. The leasing activity which would result for each of these schedules is as follows:

Schedule	Maximum Number of Sales	Number of Planning Areas
Option 2-a	32	17**
Option 2-d	39	18**
Option 2-a & 2-e	37	21*

*Excludes St. Matthew-Hall, Aleutian Basin, Bowers Basin, and Aleutian Arc.
**Excludes those above, as well as Gulf of Alaska, Kodiak, Hope Basin, and Cook Inlet.

Option 2-a would schedule annual sales in the two areas in the "high" net social value group (Central and Western Gulf of Mexico) and triennial sales in 14 other areas in the "intermediate" group. Option 2-b would add a sale in the Straits of Florida based on the recently completed section 18 analysis for that planning area. Option 2-c would defer leasing in any or all of the following six planning areas: North Atlantic; Southern California; Central California; Northern California; Washington-Oregon; and North Aleutian Basin. Option 2-d would accelerate the schedule for Option 2-a by offering biennial sales in up to eight higher-value and/or higher-interest areas: Southern California; Central California; Northern California; Eastern Gulf of Mexico; Beaufort Sea; Navarin Basin; North Aleutian Basin; and St. George Basin.

Option 2-e would designate frontier exploration sales. Suboption 2-e-i would conform to your choice for the DPP, while suboption 2-e-ii would convert to frontier exploration sales, the sales in any or all of the following planning areas: North Atlantic; Mid-Atlantic; South Atlantic; and Washington-Oregon. A frontier exploration sale is the same as a standard sale except for an additional presale step: a Request for Interest scheduled for 4 months prior to the Call for Information and Nominations to help determine whether the presale process should begin. Thus, frontier exploration sales would be proposed for areas where there is greater uncertainty regarding industry interest. In either case, as part of the annual review of the 5-year program, an assessment would be made of the utility of continuing with these sales.

Option 2-f would add a single annual sale of selected blocks in areas other than the Central and Western Gulf of Mexico to include drainage and development blocks and blocks on which bids were rejected in the preceding calendar year. This would confirm a decision made for the DPP.

Option 2-g would provide for the possibility of acceleration of sales from a triennial basis in planning areas which have relatively high net social value and/or industry interest rankings. These are identical to the candidate areas specified in the DPP.

The schedules were derived on the basis of the ranking of planning areas by quantitative section 18 factors, as modified by the expression of industry interest when the two rankings differed significantly. For example, Beaufort Sea, Norton Basin, St. George Basin, Chukchi Sea, and North Aleutian Basin, which had relatively high industry interest rankings, were retained in Option 2-a even though the leasable resources and net social value for those areas are estimated to be negligible at $19 per barrel. On the other hand, Gulf of Alaska is ranked low by industry and thus was not included in Option 2-a. Washington-Oregon is part of the triennial option, but the first sale is scheduled for late in the 5-year program, 1991, to allow time to generate additional environmental information. Finally, South Atlantic, Mid-Atlantic, and Washington-Oregon which are estimated to have significant net social value at all oil price levels analyzed were not included in the acceleration option, Option 2-d, due to relatively low industry interest, while St. George Basin and Beaufort Sea were included due to relatively high industry interest.

Each of the three schedules, as well as the schedules which would result from selection of other combinations of options, reflect a balance between the potential for environmental damage, the potential for the discovery of oil and gas, and the potential for adverse impact on the coastal zone. This balance is based primarily upon the quantitative estimates of economic benefits and social costs as well as industry interest. However, to determine the timing and location of lease sales to provide a proper balance, as required by section 18(a)(3), you should consider, in addition, all the qualitative information on section 18(a)(2) factors. Further, your decision on the final 5-year program in late 1986 or early 1987 will need to be based upon any revision to the section 18 analyses, public comments, and the final EIS.

As indicated above, the attached analysis has been structured to be consistent with the court findings on the 1982 program. However, it should not be viewed as deterministic in any sense of the word. The framework for the analysis--planning for an uncertain future with limited information--sets the tone of the entire analysis. The estimates of economic benefits are based on the best data available, but are subject to considerable uncertainty as were the estimates in the 1982 analysis. To underline this uncertainty, a variation in starting oil prices ($19 to $29 per barrel) is used in this analysis rather than just point estimates as in the 1982 analysis. The social cost and marine productivity/environmental sensitivity analyses are even more uncertain than the economic benefits. The rankings of industry interest are simple averages and do not represent the relative strength of individual company preferences or the size of holdings of companies operating on the OCS. Furthermore, both the net social value and industry interest rankings are based on geologic data and economic/environmental assumptions which are highly subject to change as new information becomes available and analytical assumptions and techniques are refined. Such changes have the potential to alter the rankings, perhaps significantly. In light of these uncertainties and the requirement to consider all the qualitative as well as quantitative information required by section 18, your policy judgments are vital to meet the Act's balancing requirements for timing and location of lease sales.

Size Comments

In their comments on the DPP issued in March 1985, the Governors submitted several comments regarding the presale process. Alabama, California, Connecticut, Delaware, Georgia, New Hampshire, New Jersey, New York, North Carolina, South Carolina, and Virginia stated general agreement with the concept of focusing on promising acreage. Some of these States also made suggestions to establish a presale process which defines even more precisely the acreage to be offered for lease. For example, Maine and Maryland proposed combining tract selection and areawide processes, and Maryland also suggested including a request for interest step for sales proposed in areas lacking commercial discoveries. Others requested better definition of the focusing on promising acreage process.

Alaska requested a return to the tract selection process. Florida, Massachusetts, and Washington recommended that smaller sale areas be defined to allow better impact analysis. Louisiana, Rhode Island, and Texas requested clarification of the presale process of focusing on promising acreage. These requests reflect a generally expressed need for better definition of this term. Oregon reiterated a request for abandoning the areawide leasing concept.

Most industry commenters recommended that the areawide presale process be retained in the next 5-year program. Several cited inequities in the procedures governing the submittal of positive and negative lease sale nominations, and they requested that the procedures be made similar for both. Two commenters expressed concern that a retreat from areawide leasing and an emphasis on consensus could cause unique exploration philosophies to be ignored or discounted.

Appendix P evaluates the effects of different sizes of lease sales that may result from the tract selection and areawide processes. The appendix was rewritten in July 1985 and is in the process of a further revision in light of comments received in response to the August 19, 1985, Federal Register Notice. New analyses will address the issues raised in the July 15, 1985, General Accounting Office report on areawide leasing. We will provide the information needed to meet the General Accounting Office recommendations "that the Secretary of the Interior consider the effects [of areawide leasing and other approaches] on competition and bid revenues in relation to anticipated benefits, and report his findings to the Congress." The revised Appendix P will be submitted for your review and possible action prior to distribution with the attached SID and other appendices when they are published later this year. This revision will enable the public to evaluate more fully your selection of a proposed program.

As of October 7, 1985, 17 comments have been received on Appendix P in response to the August 1985 Federal Register Notice. The responses from Maryland and Connecticut question the validity of using data from a mature producing area, the Gulf of Mexico, to draw conclusions about areawide or tract selection leasing for frontier areas. The respondents from three State agencies who responded expressed continued opposition to areawide leasing despite the statistics presented. New Jersey still supports focused leasing, and Louisiana favors a steadier paced leasing program as opposed to an accelerated program. The Maine State Planning Office believes that the appendix is more of a response to areawide leasing critics than a policy analysis. California finds that there is little data specific to the areawide leasing consequences for that State. The Natural Resource Defense Council disagrees with certain DOI assumptions, especially the 8 percent discount rate which they believe is inappropriately high. The Department of Energy concludes that areawide leasing has increased the present value contribution of total OCS payments to the Federal Treasury by about $3.5 billion and maintains that discount rates should be around 12 percent. Finally, the five respondents from industry all support the areawide leasing approach and basically concur with the analysis in Appendix P.

Options for Size

Under section 18, as validated by the court findings, the size of lease sales is determined by the presale process. Part III.B of the SID presents options for the presale process: focusing on promising acreage; tract selection; and areawide leasing. Tract selection was used until early 1983, areawide in mid- to late 1983, and a modified areawide approach roughly comparable to the "focusing on promising acreage" concept starting in 1984. For the DPP, you selected focusing on promising acreage for the presale process.

Tract selection as previously practiced differed from areawide leasing in two key ways: much less acreage was seriously considered for leasing; and more reliance was placed upon a consensus of Government and industry views in selecting the tracts to be offered for sale. Areawide leasing procedures allowed a far wider choice of tracts to be offered, providing opportunities for investment by firms with unique geological information and exploration strategies. Focusing on promising acreage identifies and offers acreage reasonably determined to be likely to lead to exploration and/or development of oil and gas resources. Focusing on promising acreage also provides for far earlier resolution of conflicts than areawide leasing, especially for acreage with low resource estimates, low industry interest, and high use conflicts or concerns or high environmental value.

Regardless of which presale process is selected, it is important to note that size, in terms of acreage offered at a lease sale, is partially determined by the size of the planning area and its geology. In some planning areas, such as the Central and Western Gulf of Mexico, there are numerous interesting prospects scattered over large areas, while in others, such as the North Aleutian Basin, the most interesting prospects are concentrated in a relatively small area. Furthermore, even when the geology is similar in two planning areas, the acreage offered at a lease sale may be different if the planning areas are of different total acreage. The other key determinant of the size of a sale is the result of the presale resolution of conflicts involving other uses of the sea and seabed and environmental concerns.

Based on comments on the DPP and additional analysis, a number of alternative approaches for the presale process appear on the decision sheet. These are presented as candidates for the solicitation of comments in the Federal Register Notice announcing the Proposed Program.

MINIMUM BID AND BID ADEQUACY

The last two sets of options pertain to minimum bid and bid adequacy.

Minimum Bid and Bid Adequacy Review Comments and Discussions

Some Governors made recommendations with respect to raising the minimum bid level and enlarging the maximum tract size for lease sales. Alabama recommended raising the minimum bid in nonfrontier areas. Maryland and Rhode Island endorsed establishment of a minimum bid level set on a planning area basis rather than using a single figure nationwide. Rhode Island also recommended offering some tracts under a work commitment/fixed royalty bidding system.

The petroleum industry also addressed these topics. Most comments opposed raising the current minimum bid and recommended decreasing or eliminating it. The majority of comments concerning tract size did not support expanding the current maximum. Three companies did recommend enlarging certain tracts to tailor them to specific prospects.

A number of commenters contend that the current 5-year program lowers the average bid per acre and thus does not achieve fair market value. However, as noted by the U.S. Court of Appeals and the General Accounting Office, maximizing bonus bids per acre and assuring receipt of fair market value are different concepts. As described in Appendix P, the rates of leasing that result from different presale procedures may affect statistics such as the average bid per acre or the average number of bids per tract. For example, the average number of bids per tract may be less in large sales than in small sales. As is pointed out in Appendix K, the MMS bid adequacy procedures focus Government evaluations on tracts with fewer bids in order to provide added assurances for achieving fair market value.

Large sales tend to offer many low value tracts (e.g., those in deeper water or containing smaller prospects) along with the few potentially high value prospects that tend to be offered in smaller sales. Average bid statistics reflect these differences and show a decline as areawide and focused sales have proceeded, particularly in the Gulf of Mexico where a sizeable unleased inventory of good prospects (unleased acreage which is estimated to be profitable for lessees to acquire) had accumulated prior to the start of areawide sales. Declines in the average bid due to such effects should therefore not be viewed as an indication of failure to meet the fair market value requirement. Rather, they are the natural result of offering less prospective tracts and/or tracts which are more expensive to explore and develop, such as those in deeper water or where operating conditions are remote or hazardous. It also should be noted that the decline in average bids began in 1980.

Decreases in oil price expectations since 1982 contributed to the decline in average bids evident in the 1982-84 period. Again, declines caused by such changes in the economic value of the tracts offered and bid upon are not indicative of a failure to receive fair market value.

Minimum Bid Options

The current minimum bid policy, $150 per acre (subjected to reconsideration based on experience), was adopted through Secretarial decisions of March 11, 1982, and May 4, 1982. Although the increase to $150 per acre was largely regarded as a means of increasing bonus revenue and a means of helping to assure fair market value, the minimum bid can also be set to speed up or delay leasing in specific areas. In general, the higher the minimum bid, the later will be the leasing and exploration on higher cost, higher risk prospects. Thus, the minimum bid can be set to promote exploration or to prevent premature exploration. (See Appendix F, Part V and Appendix K.)

Option 4-a would maintain the minimum bid at $150/acre and allow you to determine on a sale-by-sale basis what changes, if any, are to be made.

Bid Adequacy Review Procedures Options

In the opinion on the 1982 program, California v. Watt (II), the court found that it was reasonable for the Secretary to combine reliance on the competitive bidding process with the current tract evaluation and bid rejection procedures in order to satisfy the fair market value principle in section 18(a)(4) of the OCS Lands Act. These procedures are described in Appendix K.

Option 5-a maintains current bid adequacy review procedures and allows you to determine on a sale-by-sale basis what changes, if any, are to be made.

SUMMARY OF OPTIONS FOR DECISION

In summary, section 18 requires your formulation of a Proposed Program, including your selection of a configuration of planning areas, a leasing schedule, and a presale process. The options for your selection of a Proposed Program are listed on the attached decision sheet. Since this is a proposal and subject to subsequent decisionmaking based on suggestions received during the 90-day comment period, revisions of the section 18 analysis, and evaluation of the information which will be presented in draft and final EIS's, it is appropriate that you accompany your selection of the Proposed Program with any questions to which you desire responses from commenters.

Attachments

Proposed 5-Year Program SID Options
Decision Sheet

1. Planning Area Boundary Options:

   a. Use the configuration of planning areas and boundaries adopted for the Draft Proposed Program, with minor adjustments recommended by the Department of State. [This option is subject to modification by the selection of suboptions b, c, d, or e, below]. ____

   b. Revise the boundary between the North and Mid-Atlantic planning areas. ____

   c. Subarea deferrals from planning areas

      i. Make subarea deferrals at the 5-year program stage. Four different approaches to deferrals are outlined below.

         A. Defer subareas based on national security grounds--Department of Defense and National Aeronautics and Space Administration use areas--at the Proposed Program Stage. ____

         B. Defer the following subareas at the Proposed Program stage

            (I) Defer eight subareas offshore California as depicted in the SID: a) the area offshore Point Reyes Wilderness; b) Pt. Reyes-Farallon Islands National Marine Sanctuary; c) the area in the immediate vicinity of Cordell Bank; d) the area offshore San Francisco Bay; e) the areas offshore Monterey Bay; f) the areas offshore Big Sur; g) Santa Barbara Federal Ecological Preserve and Buffer Zone; and h) Channel Islands National Marine Sanctuary. ____

            (II) Other ____

         C. Select a set of subareas for further analysis with the decision on deferral postponed until the Proposed Final Program stage. In the interim, the set of subarea deferral candidates would be analyzed further by MMS and would be submitted to the public for comments. Those subareas would then be considered for deferral as part of the decision on the Proposed Final Program. ____

         D. Defer all decisions on subarea deferrals to the Proposed Final Program. ____

ii. Limit deferrals to the presale process, but "flag" subareas at the 5-year program stage for special attention during individual presale processes. ____

iii. Limit subarea deferrals to the presale process without "flagging" subareas but describe the process for making subarea deferrals in the presale process at the 5-year program stage. ____

d. Revise the seaward boundaries of the Northern California and Washington-Oregon planning areas to coincide with the limits of the Exclusive Economic Zone. ____

e. Other ____

2. Leasing Schedule Options:

a. Adopt the Draft Proposed Program base schedule of 32 standard sales, revised to begin in January 1987. [This option is subject to modification by the selection of suboptions b, c, d, e, f, g, or h, below]. ____

b. Add a single sale in the Straits of Florida in 1991. ____

c. Defer leasing in any or all of the following six planning areas:

i. North Atlantic ____
ii. Southern California ____
iii. Central California ____
iv. Northern California ____
v. Washington-Oregon ____
vi. North Aleutian Basin ____
vii. All six areas ____

d. Adopt biennial leasing in any or all of eight areas with higher value and/or higher interest:

i. Southern California ____
ii. Central California ____
iii. Northern California ____
iv. Eastern Gulf of Mexico ____
v. Beaufort Sea ____
vi. Navarin Basin ____
vii. North Aleutian Basin ____
viii. St. George Basin ____
ix. All eight areas ____

e. Designate Frontier Exploration Sales as follows:

i. Confirm any or all of the areas designated in the Draft Proposed Program for frontier exploration sales:

-Gulf of Alaska ____
-Kodiak ____
-Cook Inlet ____
-Hope Basin ____
-Shumagin (1991) ____
-All five areas ____

ii. Add frontier exploration sale designation to all sales in any of or all of the following planning areas:

-North Atlantic ____
-Mid-Atlantic ____
-South Atlantic ____
-Washington-Oregon ____
-All four areas ____

f. Supplemental sales: Hold annual sales of rejected bid blocks offered in the preceding year and drainage and development blocks outside of the Central and Western Gulf of Mexico ____

g. Acceleration Provision: Provide for the possible acceleration of OCS sales in areas of higher value and/or higher interest from a triennial to a biennial basis (but not so as to increase the total number of sales in any planning area in the approved program).

i. Propose or request comments on any or all of the following triggers for the possible acceleration of OCS oil and gas leasing

	Propose	Request Comments
(A) Geologic Trigger: a finding by the Secretary that a new discovery in a planning area indicates that biennial leasing there is in the national interest	____	____
(B) Economic Triggers:		
(I) Activation of the International Energy Agency's oil sharing agreement	____	____
(II) Drawdown of the Strategic Petroleum Reserve (SPR) because of a severe oil supply disruption	____	____
(III) Major disruption in Mideast oil shipments	____	____
(IV) Imports of crude oil and refined petroleum products (excluding those for the SPR) reach a specified percentage of the trade deficit over a specified period	____	____
(V) Imports of crude oil and refined petroleum products (excluding those for the SPR) reach a specific percentage of total domestic consumption of petroleum products over a specified period	____	____
(VI) The price of imported crude oil (U.S. refiners' acquisition cost as computed by EIA) rises by a specified amount or percent over a specified period	____	____
(VII) Net imports of petroleum (excluding those for the SPR) are projected by EIA to equal or exceed a specified percent of U.S. consumption of refined petroleum products	____	____
(VIII) Oil prices are projected by EIA to increase by a specified amount or percent or reach a specified level	____	____
(IX) Items I through VIII above	____	____
(X) Other	____	____

ii. Select areas for the potential acceleration of OCS sales

(A) Any or all of the eight areas selected in the Draft Proposed Program decision:

-Southern California ____
-Central California ____
-Northern California ____
-Eastern Gulf of Mexico ____
-Beaufort Sea ____
-Navarin Basin ____
-North Aleutian Basin ____
-St. George Basin ____
-All eight areas ____

(B) All areas scheduled for triennial sales ____

h. Other ____

3. Size/Presale Process Options:

a. Focusing on Promising Acreage

i. Use the presale approach of focusing on promising acreage ____

ii. Solicit comments in the Federal Register Notice announcing the Proposed Program on possible techniques for implementing that approach ____

(A) - The recommendation of the Governor of Maryland that the presale process combine the tract selection approach for blocks within 50 miles of shore and areawide procedures for blocks beyond that limit. ____

(B) - Areawide sales in mature areas, tract selection sales in frontier areas. ____

(C) - The recommendation of the Governor of Maine that industry nominate in units of 100 blocks. ____

(D) - The recommendation of Massachusetts that nomination procedures be revised so as to request more detailed information from industry on areas of interest. ____

(E) - The recommendation of the API, NOIA, and a number of oil and gas producers that nomination procedures be revised so as to request more detailed information concerning "negative nominations." ____

(F) - Proposals to limit the amount of acreage leased by limiting the award of leases. For example, after deferring blocks, as appropriate, in order to avoid environmental and multiple-use conflicts, offer the remaining blocks, but place a cap on the number of leases to be awarded, such as a percentage of the total planning area or a fixed number determined on a planning area basis, with leases to be awarded in the order of the acceptable high bids. ____

(G) - Items A through F above ____

(H) - Other ____

b. Tract Selection Sales

i. Hold sales based on tract-specific nominations generally offering up to 2 million acres. ____

ii. Hold sales based on tract-specific nominations with actual acreage offered dependent on the magnitude of nominations, hydrocarbon potential, and environmental and multiple-use considerations. ____

c. Hold Areawide Sales. For the purpose of this option, "areawide sales" has the meaning of the initial areawide approach described in the Secretarial Issue Document. ____

d. Other ____

4. Minimum Bid Options:

a. Maintain the $150/acre minimum bid and determine on a sale-by-sale basis what changes, if any, are to be made ____

b. Other ____

5. Bid Adequacy Review Options:

a. Maintain current bid adequacy review procedures and determine on a sale-by-sale basis what changes, if any, are to be made ____

b. Other ____

Current Leasing Schedule Overlap With Option 2-a for the Proposed Program
(Base Schedule of Standard Sales)*

	1983	1984	1985	1986	1987	1988	1989	1990	1991	No. of Sales
ATLANTIC										4
North		82				96			S	
Mid-	76			111			S			
South	78			90			108			
GULF OF MEXICO										12
Western	74	84	102	105	S	S	S	S	S	
Central	72	81	98	104	110	S	S	S	S	
Eastern	69(II)	79	94			S			S	
PACIFIC										6
Southern CA		80			95			S		
Central CA	73						S			
Northern CA						91			S	
Washington-Oregon									S	
ALASKA										10
Beaufort Sea		87			97			S		
Chukchi Sea					109			S		
Norton Basin	57			100			S			
Navarin Basin		83			107			S		
St. George Basin	70			89			101			
N. Aleutian Basin				92			S			
Shumagin						86				
									Total	32

Sales to the left of the vertical line are in the current 5-year leasing schedule.
Sales to the right of the vertical line are a part of this option for the Proposed Program.

S = Sale not yet numbered. Sale numbers are those in the 1982 program.

*This table has been prepared based on the latest available scheduling information. Administrative considerations may delay the holding of a number of sales--Sales 111, 90, 97, 107, 109, 86, 101, and possibly others. If such a change occurs, the leasing schedule would be implemented so as to factor in that change, consistent with the scheduling policy selected by the Secretary. This also applies to the following two schedule tables.

Current Leasing Schedule Overlap with Option 2-d for the Proposed Program
(Biennial Sales in up to 8 areas)*

	1983	1984	1985	1986	1987	1988	1989	1990	1991	No. of Sale
ATLANTIC										4
North		82				96			S	
Mid-	76			111			S			
South	78			90			108			
GULF OF MEXICO										13
Western	74	84	102	105	S	S	S	S	S	
Central	72	81	98	104	110	S	S	S	S	
Eastern	69(II)	79	94		S		S		S	
PACIFIC										8
Southern CA		80			95		S		S	
Central CA	73					S		S		
Northern CA						91		S		
Washington-Oregon									S	
ALASKA										14
Beaufort Sea		87			97		S		S	
Chukchi Sea					109			S		
Norton Basin	57			100			S			
Navarin Basin		83			107		S		S	
St. George Basin	70			89		101			S*	
N. Aleutian Basin				92		S		S		
Shumagin						86				
Gulf of Alaska			88							
									Total	39

Sales to the left of the vertical line are in the current 5-year leasing schedule. Sales to the right of the vertical line are part of this option for the Proposed Program.

S = Sale not yet numbered. Sale numbers are those in the 1982 program.

*The 26-month presale process for Alaska OCS sales results in the appearance that some of the areas proposed for biennial leasing have triennial leasing. A monthly schedule would show that the following 8 areas are proposed in this option for leasing as near to biennial as possible: Southern, Central, and Northen California; Eastern Gulf of Mexico; Beaufort Sea; Navarin Basin; St. George Basin; and North Aleutian Basin.

Current Leasing Schedule Overlap with Options 2-a and 2-e or the Proposed Program
(Base Schedule + up to 10 Frontier Exploration Sales)

	1983	1984	1985	1986	1987	1988	1989	1990	1991	No. of Sales
ATLANTIC										4
North		82				96[S+]			S+	
Mid-	76			111			S+			
South	78			90			108[S+]			
GULF OF MEXICO										12
Western	74	84	102	105	S	S	S	S	S	
Central	72	81	98	104	110	S	S	S	S	
Eastern	69(II)	79	94			S			S	
PACIFIC										6
Southern CA		80			95			S		
Central CA	73						S			
Northern CA						91			S	
Washington-Oregon									S+	
ALASKA										15
Beaufort Sea		87			97			S		
Chukchi Sea					109			S		
Norton Basin	57			100			S			
Navarin Basin		83			107			S		
St. George Basin	70			89			101			
N. Aleutian Basin				92			S			
Shumagin						86			S+	
Kodiak									S+	
Cook Inlet									S+	
Gulf of Alaska						S+				
Hope Basin									S+	
									Total	37

Sales to the left of the vertical line are in the current 5-year leasing schedule. Sales to the right of the vertical line are part of this option for the Proposed Program.

S = Sale not yet numbered. Sale numbers are those in the 1982 program.
S+ = Frontier Exploration Sale.

Maps Depicting the 26 Planning Areas of the OCS
Pursuant to the Decision on the Draft Proposed Program
Map 1

OCS PLANNING AREAS

Map 2

Attachment 4

PROPOSED PROGRAM

5-Year Outer Continental Shelf Oil and Gas Leasing Program for January 1987 - December 1991

Secretarial Issue Document

OCTOBER 1985

PROPOSED PROGRAM

5-Year Outer Continental Shelf Oil and Gas Leasing Program for JANUARY 1987 - DECEMBER 1991

SECRETARIAL ISSUE DOCUMENT

OCTOBER 1985

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*In order to keep down printing costs, these lengthy pieces are not reproduced with this Secretarial Issue Document (SID) for the Proposed Program. They are, however, part of the decision materials considered by the Secretary for his decision on the Proposed Program. Copies of these pieces or other individual appendices can be obtained by special request to the Branch of Program Development and Planning, Minerals Management Service (645), 1800 C Street, N.W., Washington, D.C. 20240, (202) 343-1072.

Executive Summary

This revised Secretarial Issue Document (SID) provides the basis for the decisions by the Secretary of the Interior (Secretary) that will structure a Proposed 5-Year Outer Continental Shelf (OCS) Oil and Gas Leasing Program for the period 1987 through 1991.

The program is being developed under section 18 of the OCS Lands Act, as amended. Under the requirements of section 18, as they have been interpreted by rulings of the U.S. Court of Appeals for the District of Columbia Circuit, the Secretary must consider a variety of factors bearing on the costs and benefits of leasing OCS oil and gas. The Secretary must then develop a schedule of lease sales which will "best meet national energy needs," balancing the potential benefits of the discovery of oil and gas against the potential costs.

The Proposed Program will be the second of three stages the Secretary is required to develop in the process of formulating the 5-Year OCS Leasing Program. Review copies of the Draft Proposed Program were issued to the Governors of coastal States, affected Federal agencies, and the public in March 1985. At the end of 1985 or the beginning of 1986, the second stage--the Proposed Program--is scheduled to be submitted for review to those same parties and to the Attorney General and Congress. The third stage--the Proposed Final Program--is scheduled for transmittal to the President and Congress in early 1987 with final approval by the Secretary slated for 60 days thereafter.

A draft environmental impact statement (EIS) will be issued with the second stage and the final EIS prior to the decision on the third stage. The Secretary's decision on the Proposed Program will serve as the proposal for the draft EIS.

This SID with its appendices serves a number of functions.

1. It provides information on the various types of costs and benefits which the Secretary is required to consider, and it documents the sources and methods used in developing the new program.

2. It develops a framework and guidelines for balancing costs and benefits, recognizing the inherent limitations in the information about and forecasts of future conditions in the world oil market.

3. It sets forth options from which choices can be made concerning the size, timing, and location of lease sales in the Proposed Program and to assure the receipt of fair market value.

The SID for the Proposed Program has a number of new features which distinguish it from the SID for the Draft Proposed Program: it covers sales beginning in 1987 rather than mid-1986; it provides ranges and sensitivity tests rather than single-value estimates for a variety of quantitative measures; it contains refined analyses of benefits and costs; it summarizes and responds to comments on the Draft Proposed Program; it presents an estimate of the net social value of the base leasing schedule option; and it contains new decision options.

I. Introduction

A. Background

I.A.1. History

The 5-Year OCS Oil and Gas Leasing Program for 1987 through 1991 is the third program to be developed under section 18 of the OCS Lands Act, as amended (43 U.S.C. 1344). Prior to the OCS Lands Act Amendments of 1978, which added section 18 in its entirety, OCS leasing programs had been issued as a discretionary act of the Secretary of the Interior (hereafter, the Secretary). Regulations implementing section 18 appear at 30 CFR 256.14-20.

The first program prepared under section 18 received final approval in June 1980. That program scheduled 36 sales in 16 OCS planning areas for the period September 1980 through June 1985. Those sales were to be held using the "tract selection" approach which offered a limited amount of acreage, as described in Part III.B and Appendix P. Sales held under that leasing program resulted in the leasing of more than 2 million acres in 1981, the first year in which the 2 million acre level was surpassed since the announcement of the goal of leasing 10 million acres per year in 1974. Bonus bid levels of nearly $5,000 per acre on some tracts in 1981 provided strong signals that there were many good prospects for investment in exploration for oil and gas in the Government's inventory of unleased tracts.

The 1980 program was challenged in the U.S. Court of Appeals for the District of Columbia Circuit (hereafter, the court). /1 In its 1981 decision, the court found fault with the analysis performed for that program, but the court allowed leasing to continue and gave guidance for the formulation of the second program, then under development. The Secretary's compliance with the court's guidance was set forth in a SID and a set of appendices dated March 1982.

In July 1982, the second 5-year program developed under section 18 was given final approval by the Secretary. This program, currently in effect, scheduled 41 sales in 18 OCS planning areas between August 1982 and June 1987. Of those 41 sales, virtually all sales to be held after April 1983 were to use a new "areawide" approach to offer much more acreage, as described below in Part III. B and Appendix P.

The 1982 leasing program was also challenged in court. In a July 1983 opinion, the court upheld the 1982-1987 program formulation as having fully complied with the statute and the guidance it had set forth in its 1981 opinion. /2 Appendix A contains selected quotations from the OCS Lands Act, as amended, 30 CFR 256.14-20, and a discussion of the compliance of the development of this third 5-year program with section 18 as interpreted by the court.

/1 California v. Watt, 668 F.2d 1290 (hereafter, California v. Watt (I)), decided October 6, 1981.

/2 California v. Watt, 712 F.2d 584 (1983), (hereafter, California v. Watt (II)) decided July 5, 1983.

I.A.2. Development of the New Program

Under the procedural requirements of section 18, the development of a new program takes about two years. The initiation of development of the new program was announced in letters to the Governors of coastal States and to interested Federal Agencies, dated July 5, 1984, and in a Federal Register Notice published on July 11, 1984 (49 FR 28332). The Secretary's selection of a Draft Proposed Program was announced in letters to the Governors of coastal States and to interested Federal Agencies dated March 19, 1985, and in a Federal Register Notice published on March 22, 1985 (50 FR 11585).

The basic features of the Draft Proposed Program are as follows:

1. Planning Area Boundaries for the Draft Proposed Program

The Draft Proposed Program selection revised the July 1984 description by establishing outer boundaries for planning areas; reconfiguring the OCS from 24 to 26 planning areas by dividing the South Atlantic into two areas (South Atlantic and Straits of Florida) to allow a more concentrated review of those areas under the provisions of section 18; and reconfiguring the planning areas offshore California from two to three to allow a more concentrated section 18 review of those areas as well as to respond to public comments.

2. The Leasing Schedule for the Draft Proposed Program

Over the period mid-1986 through mid-1991, the Draft Proposed Program provided for 33 standard sales, 5 frontier exploration sales, and 5 supplemental sales.

This contrasts with the current program (as approved in July 1982), which provided for 40 standard sales and 1 reoffering sale. The new draft schedule proposes the continuation of annual sales in the two highest-value, highest-interest areas: the Central and Western Gulf of Mexico. The Draft Proposed Program scheduled triennial sales in 15 other areas and thus slowed the pace of leasing in contrast with the biennial pace in the current 5-year program.

The first OCS sale for the area offshore Washington and Oregon since 1964 was proposed for 1991, given the value of that area's resources and industry interest. The schedule also proposed the first sale in Hope Basin, offshore Alaska, also in 1991 /1. The sales for these areas were proposed late in the 5-year period to allow time for the necessary environmental studies to be performed.

a. The Base Schedule

The base schedule proposed 33 standard sales in 17 planning areas. Eleven of those sales are sales carried over from the current to the new program.

b. Frontier Exploration Sales Offshore Alaska

Five frontier exploration sales were proposed offshore Alaska to increase the flexibility of the schedule to respond to possible future changes in prices and other economic conditions or improved geologic and geophysical data. These five sales were proposed for the Gulf of Alaska, Cook Inlet, Shumagin, Hope Basin, and Kodiak.

/1 The June 1980 program had proposed a sale in Hope Basin in May 1985.

These frontier exploration sales would include an additional presale step: a Request for Interest scheduled for 4 months prior to the Call for Information and Nominations. Responses to each Request will be used to help determine whether the approximately 2-year sale process should proceed in those areas. The scheduling of these sales provides flexibility to the program. Under current conditions, the Department would not necessarily see sales in these areas as viable. Yet conditions could change so that having the option to initiate and hold these sales could be in the Nation's interest. The annual review of the program under section 18(e) will also be used to determine whether to proceed with these sales.

c. Supplemental Sales

The schedule also included an annual sale for a small number of selected blocks in areas other than the Central and Western Gulf of Mexico: drainage and development blocks; and blocks on which bids were rejected in the preceding calendar year. These sales would provide for: (1) The expeditious offering of blocks in which serious industry interest can reasonably be anticipated; (2) orderly development of OCS resources (increasing the potential for actual development and reducing the time necessary to bring new fields into production; and (3) minimization of costs of delay. These blocks will only be offered after compliance with the requirements of the National Environmental Policy Act, the OCS Lands Act, and other applicable statutes. The environmental assessment documentation for each of these sales would be released at approximately the same time as the Proposed Notice of Sale. If it is determined that an EIS is required for one of these sales, revised presale milestones will be issued.

d. Areas in Which No Sales Are Proposed in the Draft Proposed Program

The schedule proposed no sales in St. Matthew-Hall, Aleutian Arc, Aleutian Basin, and Bowers Basin so as to concentrate management resources on other areas with higher resource potential and industry interest. No sale was scheduled for the Straits of Florida since this area was not yet analyzed as a separate planning area.

e. Acceleration (Flexibility) Provision

To comply fully with the statutory requirement to meet national energy needs over the 5 years of the program, the schedule should have the flexibility to respond to changing conditions. Thus, the Draft Proposed Program included a provision to accelerate sales in eight areas of higher value and/or higher interest (but not so as to increase the total number of sales in any planning area in the approved program). The areas where such acceleration would be considered include: Southern California; Eastern Gulf of Mexico; Central California; Northern California; Navarin Basin; Beaufort Sea; North Aleutian Basin; and St. George Basin. Specific guidelines for the implementation of the acceleration provision were to be developed for the Proposed Program.

3. Size of Lease Sales in the Draft Proposed Program

It was proposed that the size of lease sales be determined by a presale process which results in focusing on promising acreage. Promising acreage is that which is reasonably determined to be likely to lead to exploration and/or development of oil and gas resources. That determination will be made by means of a

consultative process which will provide for the early resolution of conflicts based on information and nominations obtained from affected Federal Agencies, State and local governments, the public, and potential bidders, as well as Minerals Management Service analysis. Where strong environmental or other conflicts exist the focusing on promising acreage concept provides that these issues be addressed early so that, depending on the merits of each case, deferral of areas can be considered.

The offering of promising acreage will give effect to DOI's desire to make available for lease areas of hydrocarbon potential as identified by industry and MMS, while remaining cognizant of the particular circumstances relevant to each sale. The various OCS areas and the adjacent onshore regions vary significantly in terms of exploration and development history, onshore support capability, and possible multiple-use conflicts. In preparing for leasing activity, regional differences will be taken into account on a case-by-case, sale-by-sale basis, and the emphasis will be on consultation, and, wherever possible, consensus.

4. Assurance of Receipt of Fair Market Value in the Draft Proposed Program

Section 18(a)(4) provides that leasing activities are to be conducted so as to assure receipt of fair market value for lands leased and rights conveyed. The policy option selected for the Draft Proposed Program maintains current procedures for assuring the receipt of fair market value. The option selected also provided for a review of the question of whether the minimum bid level should be changed either in general or on a variable basis for different planning areas.

New Features of the SID for the Proposed Program

The new 5-year program is now planned to cover the period 1987 through 1991. The Draft Proposed Program focused on the period mid-1986 through mid-1991. The period covered by the new program has moved by 6 months because of various administrative considerations, including additional time allotted for the study of subareas which are potential candidates for deletion from the new program. The assumptions of the section 18 analyses have been made consistent with the new period to be covered by the program.

The SID for the Draft Proposed Program contained the preliminary analyses required by section 18. In response to the DOI's March 1985 request for comments, many commenters provided helpful comments and criticism of the analysis. This SID contains an updated and refined but still preliminary version of those analyses and decision options for the second stage of the development of the new program--the Proposed Program. The Proposed Program selected by the Secretary will serve as the proposed Federal action to be analyzed in the EIS. The final section 18 analyses and the final EIS will be a part of the decision materials for the Proposed Final Program scheduled for issuance in late 1986 or early 1987.

The Proposed Program will contain a schedule of proposed lease sales "indicating, as precisely as possible, the size, timing, and location of leasing activity" and program policies selected by the Secretary while at the same time reflecting the provisional nature of the "Proposed" stage.

The Proposed Program will indicate the proposed timing of presale steps for sales to be held beyond the current schedule. Sales will continue to be held in accordance with the current schedule until the new program receives final approval.

Under section 18(c)(2) of the OCS Lands Act and 30 CFR 256, the Proposed Program, the analyses on which it is based, and the draft EIS will be submitted for review to the Governors and local governments of coastal States and a Notice on the Proposed Program will be published in the Federal Register. Comments of the Governors and localities and of others on the Proposed Program and the draft EIS will be considered in the preparation of the Proposed Final Program and the final EIS.

Copies of the July 1984 and March 1985 Federal Register Notices appear in Appendix M. Development of the new program has also been the subject of consultation under the auspices of the OCS Advisory Board's Policy Committee, pursuant to regulations at 30 CFR 256.19.

Comments were received from Governors or their representatives, State and Federal Agencies, State legislators, local government entities, oil and gas industry members or associations, and from the general public. Most responses are briefly summarized below and all are detailed in Appendix B of this SID. Summaries of comments relevant to decision options also appear in Part III of this SID.

I.A.3 General Summary of Comments on the Draft Proposed Program

Approximately 337 comments were received on the Draft Proposed Program: 30 from the Governors of 23 coastal States; 4 from Members of Congess; 40 from companies or groups; 12 from Federal Agencies; 43 from State agencies and local governments; and 208 from individuals.

Section 18(a)(2) Factors Exclusive of Industry Rankings

Respondents frequently cited potential impacts that could result from OCS development, including potential effects on navigation and shipping, especially off California; effects on environmentally sensitive areas; potential conflicts with other uses of the sea and seabed including military uses; and potential fishing conflicts. Governors commented on onshore impacts on air quality, coastal infrastructure and the potential environmental and long-term economic impacts that could result from a disregard for equitable sharing. The States also expressed concern over potential conflicts with local coastal management plans. The biological significance and productivity of fisheries and their role in the Nation's food supply were identified as possible conflicts. Coastal tourism and recreation especially in New Jersey, New York, and California were cited as concerns. Among the many concerns expressed in comments from environmental and other interest groups, the following issues were most frequently cited: cumulative impacts, air quality, environmental sensitivity, deep water technology, public involvement, pace of leasing, fiscal impacts, other uses of the seabed and coasts, vessel traffic lanes, oil spill risks and response, ocean dumping of drilling by-products, infrastructure burdens, effects on coastal dependent economies, oil and gas transportation strategies, and whales and other marine migratory species.

Numerous comments focused on the need for equitable sharing of developmental benefits and environmental risks. Louisiana commented that the 5-year program would place an even greater burden on the Gulf Coast, citing scheduling concessions to all areas of the country except the Central and Western Gulf of Mexico. The high risks of exploration and low hydrocarbon potential were frequently cited as reasons for removing California's north coast from leasing consideration. Local governments, especially in California, frequently commented that developmental benefits and environmental risks were inadequately considered in the Draft Proposed Program.

With respect to relative marine productivity and environmental sensitivity, the U.S. Environmental Protection Agency (EPA) and North Carolina believe that a broader view and use of more meaningful indicators of relative marine productivity should be adopted. New York commented that environmental sensitivity figures are misleading as to the environmental importance of a region. South Carolina, numerous local governments in California, and several environmental groups believe that the Draft Proposed Program does not adequately consider the relative marine productivity and environmental sensitivity of planning areas.

With regard to oil and gas transportation networks and strategies, several commenters cited navigation concerns and shipping safety. The Coast Guard expressed concern that conflicts, which may arise when leases are granted in and near existing and potential shipping lanes, have not been given adequate treatment in the Draft Proposed Program. The Coast Guard called for coordinating lease sale areas with a scheduled system-wide adjustment of sealanes. Areas off California were singled out as needing such consideration. The California Coastal Commission recommended that oil transportation by pipeline be required for all areas of the Pacific coast. Numerous local governments in California called for adequate consideration for navigation and sealanes; Ventura County recommended resolving transportation issues prior to leasing. Santa Barbara County recommended deleting tracts from leasing located in the Santa Barbara Channel Vessel Traffic Separation Scheme. Where mentioned in comments, pipeline transportation is generally favored over tankers.

Most comments on the topic of relevant environmental and predictive information recommended continuation of the environmental studies program, and in some cases a call was made for supplemental efforts to the existing program. The National Oceanic and Atmospheric Administration stated that certain sales in Alaska are scheduled too early to allow environmental studies to be completed before the exploration stage. Florida recommended no leasing in portions of the Eastern Gulf of Mexico, citing a lack of environmental studies data. Oregon called for formation of a Pacific Northwest working group to determine whether OCS areas off Washington and Oregon should be placed on the 5-year program schedule and to design an environmental studies program. Oregon expressed concern that 3 years is inadequate time to complete studies necessary to support a lease sale in the area and suggested establishing an environmental studies field office in Newport, OR, at the Mark O. Hatfield Marine Science Center; Washington made a similar request for a field office to be located in Washington. Florida Public Interest Research Group recommended sufficient funding and coordination to complete environmental studies.

Comments on Possible Changes to the Leasing Process

Many commenters expressed strong support for the Secretary's emphasis on consultation and consensus, the focusing on promising acreage concept, and the triennial pace of leasing in most areas outside the Central and Western Gulf of Mexico. Commenters asked for clarification of the focusing on promising acreage concept, particularly how it differs from both areawide leasing and the tract selection process. Similarly, the acceleration provision in the leasing process elicited many comments calling for clarification of how it would be implemented.

The presale process was the focus of numerous comments. There were frequent criticisms of areawide leasing and calls for a return to a tract selection process. Louisiana called for a description of specific prelease mechanisms and procedures. Maine proposed combining the best features of both the areawide and tract selection leasing process, specifically recommending a "middle ground" option. Maryland proposed a split presale process employing areawide leasing in deepwater areas and tract selection for nearshore areas. Rhode Island called for a Request for Interest step to be used in unproven areas such as the North Atlantic.

Ten States (Alabama, Connecticut, Delaware, Maryland, New Hampshire, New Jersey, New York, North Carolina, South Carolina, and Virgina) expressed general agreement with the proposed prelease process. Industry continued to favor the areawide approach. Several companies including Chevron, Marathon, and Exxon as well as the American Petroleum Institute (API) expressed some reservations about adding unnecessary steps to the presale process.

With regard to the proposed means for pursuing flexibility in the leasing process, reactions were mixed. The U.S. Department of Energy endorsed the proposed acceleration provision. The EPA suggested altering diligence requirements as an alternative. Alaska, Massachusetts, and South Carolina stated a need for more information. Florida has concerns that accelerated leasing will conflict with the goals of the environmental studies program. Oregon requested deletion of the acceleration provision. Rhode Island called the accelaration provision a "good idea," but desires more information. A few commenters said that the acceleration provision may be inconsistent with the OCS Lands Act. Numerous local government and environmental groups' responses opposed the acceleration provision, but industry generally endorsed the proposal. Several industry responses, including BP Alaska, NOIA, Tenneco, Sohio, Union Texas Petroleum, Exxon, WOGA, and the U.S. Chamber of Commerce emphasized the need for overall reliability in the program.

Commenters' Size, Location, and Timing Recommendations

Opinions on the size of sales as determined by the prelease process were divided. Areawide leasing was generally advocated by industry and opposed by others. Those opposed frequently called for a return to tract selection procedures. The concept of "focusing on promising acreage," while generally well received, caused commenters to reserve judgment pending a fuller explanation of its meaning. Some States, Massachusetts for example, recommended focusing on potential oil- and-gas-bearing structures or physiographic regions rather than on geographic boundaries of planning areas. Texas, on the other hand, expressed difficulty in discerning the practical difference between areawide leasing and focusing on promising acreage.

On the topic of location, Gulf Coast States generally indicated that more sales should be held outside the Central and Western Gulf of Mexico. Alaska agreed with the decision to drop St. Matthew-Hall, Aleutian Arc, Aleutian Basin, and Bowers Basin planning areas from the leasing schedule. Oregon gave qualified approval to including the Washington-Oregon planning area on the leasing schedule, but requested a seaward boundary of 125° instead of 128° W. longitude. State agencies and local governments generally opposed leasing off Central and Northern California. The City of Eureka, however, endorsed leasing in the Northern California planning area. Industry stated general agreement with the location of proposed sales. At least one industry response called for renewed emphasis on leasing in Alaska and California OCS regions, citing the potential for new resources that exists there. Citizen comments generally opposed leasing off California.

The triennial pace of leasing was generally viewed favorably. Louisiana and Texas expressed concern over annual sales in the Gulf of Mexico, but Alabama supported the pace and called for accelerating sales in the Eastern Gulf of Mexico if major discoveries are found in that area. Maine, Massachusetts, and New Jersey expressed reservations over the timing of sales in the North Atlantic planning area. Massachusetts stated that only one sale there during the 5-year period is warranted. Several California respondents alleged there was no slowing of the sale pace, since the number of planning areas was increased from 2 to 3. More than one California legislator commented that the reconfiguration, coupled with the introduction of supplemental sales, accelerated, rather than slowed, the pace in some areas. Numerous industry respondents preferred a biennial pace of leasing for most areas outside the Central and Western Gulf of Mexico.

General Accounting Office Report

On July 15, 1985, the General Accounting Office (GAO) published a report entitled "Early Assessment of Interior's Area-Wide Program for Leasing Offshore Lands." This report found that "more offshore lands have been leased and that exploration is progressing at a faster rate under the area-wide program." It also reported that it could not yet " assess effects on production, imports, prices, employment or total government revenues." The GAO concluded that competition had declined and that the "shift to area-wide leasing was responsible for an average reduction in bids of $541 per acre leased" out of the decline from $2,624 per acre under the tract selection program to $686 per acre.

The GAO recommended "that the Secretary of the Interior, in developing the next 5-year leasing schedule, consider the effects identified on competition and bid revenues in relation to anticipated benefits, and report his findings to Congress." Appendix P reviews the GAO analysis of competition and bonuses and analyzes the investment and revenue effects of the pace of leasing under different approaches. The results are summarized in Part III.B.

Appendix P

A revised Appendix P (Analysis of Tract Selection and Areawide Leasing Approaches) was issued several months after release of the Draft Proposed Program. It was sent to the Governors of coastal States for comment on July 16, 1985, and a notice announcing its availability for public comments was published in the Federal Register on August 19, 1985 (50 FR 33418). Seventeen comments were received on the analysis from 5 companies; 10 States; and 2 others.

General and Miscellaneous Comments

Topics most commonly addressed apart from section 18 considerations and those requested in the March 1985 Federal Register Notice included the following: expressions of support for OCS revenue sharing, calls for speedy resolution of the 8(g) issue, continuing support for the Congressional moratorium/1 and negotiation of a long-term agreement to protect environmentally sensitive areas off California, the need for alternative energy strategies based on renewable energy sources and conservation, and concern for the onshore impacts on coastal dependent economies. The States, as expected, continued the call for OCS revenue sharing. California and Texas want negotiations to resolve 8(g) concerns. Citizen response calling for continuation of the moratorium off California was heavy. Local governments in California frequently called for continuing the moratorium unless a long-term agreement on the status of sensitive areas can be achieved.

In view of these concerns, Secretary of the Interior Donald Hodel and members of the California Congressional Delegation announced on July 16, 1985, a preliminary agreement which would have allowed the leasing of 150 tracts out of 6,460 that had been under moratorium off California. The preliminary agreement was subject to receiving additional advice and comments. Secretary Hodel held a series of town hall meetings in 11 California cities in August to receive comments. Based on that information, over 2,000 pieces of correspondence, and additional analysis, he found that the preliminary agreement was not in the national interest and wrote to the Senate and House indicating so on September 5, 1985. On September 11, 1985, he testified before the House and on September 17, 1985, before the Senate, reporting his thoughts on the preliminary agreement.

A more detailed summary of comments may be found in Appendix B.

The following pages contain a copy of section 18 and a copy of maps depicting the 26 planning areas of the OCS pursuant to the decision on the Draft Proposed Program.

1/ The FY 1985 DOI Appropriation Act contained a restriction prohibiting the leasing of 44.8 million areas off California and in the North Atlantic.

"SEC. 18. OUTER CONTINENTAL SHELF LEASING PROGRAM.—(a) The Secretary, pursuant to procedures set forth in subsections (c) and (d) of this section, shall prepare and periodically revise, and maintain an oil and gas leasing program to implement the policies of this Act. The leasing program shall consist of a schedule of proposed lease sales indicating, as precisely as possible, the size, timing, and location of leasing activity which he determines will best meet national energy needs for the five-year period following its approval or reapproval. Such leasing program shall be prepared and maintained in a manner consistent with the following principles: 43 USC 1344.

"(1) Management of the outer Continental Shelf shall be conducted in a manner which considers economic, social, and environmental values of the renewable and nonrenewable resources contained in the outer Continental Shelf, and the potential impact of oil and gas exploration on other resource values of the outer Continental Shelf and the marine, coastal, and human environments.

"(2) Timing and location of exploration, development, and production of oil and gas among the oil- and gas-bearing physiographic regions of the outer Continental Shelf shall be based on a consideration of—

"(A) existing information concerning the geographical, geological, and ecological characteristics of such regions;

"(B) an equitable sharing of developmental benefits and environmental risks among the various regions;

"(C) the location of such regions with respect to, and the relative needs of, regional and national energy markets;

"(D) the location of such regions with respect to other uses of the sea and seabed, including fisheries, navigation, existing or proposed sealanes, potential sites of deepwater ports, and other anticipated uses of the resources and space of the outer Continental Shelf;

"(E) the interest of potential oil and gas producers in the development of oil and gas resources as indicated by exploration or nomination;

"(F) laws, goals, and policies of affected States which have been specifically identified by the Governors of such States as relevant matters for the Secretary's consideration;

"(G) the relative environmental sensitivity and marine productivity of different areas of the outer Continental Shelf; and

"(H) relevant environmental and predictive information for different areas of the outer Continental Shelf.

"(3) The Secretary shall select the timing and location of leasing, to the maximum extent practicable, so as to obtain a proper balance between the potential for environmental damage, the potential for the discovery of oil and gas, and the potential for adverse impact on the coastal zone.

Fair market value.

"(4) Leasing activities shall be conducted to assure receipt of fair market value for the lands leased and the rights conveyed by the Federal Government.

(continued)

Appropriations and staff, estimates.

"(b) The leasing program shall include estimates of the appropriations and staff required to—

"(1) obtain resource information and any other information needed to prepare the leasing program required by this section;

"(2) analyze and interpret the exploratory data and any other information which may be compiled under the authority of this Act;

Environmental studies and impact statement.

"(3) conduct environmental studies and prepare any environmental impact statement required in accordance with this Act and with section 102(2)(C) of the National Environmental Policy Act of 1969 (42 U.S.C. 4332(2)(C)); and

"(4) supervise operations conducted pursuant to each lease in the manner necessary to assure due diligence in the exploration and development of the lease area and compliance with the requirements of applicable law and regulations, and with the terms of the lease.

"(c)(1) During the preparation of any proposed leasing program under this section, the Secretary shall invite and consider suggestions for such program from any interested Federal agency, including the Attorney General, in consultation with the Federal Trade Commission, and from the Governor of any State which may become an affected State under such proposed program. The Secretary may also invite or consider any suggestions from the executive of any affected local government in such an affected State, which have been previously submitted to the Governor of such State, and from any other person.

Publication in Federal Register.

"(2) After such preparation and at least sixty days prior to publication of a proposed leasing program in the Federal Register pursuant to paragraph (3) of this subsection, the Secretary shall submit a copy of such proposed program to the Governor of each affected State for review and comment. The Governor may solicit comments from those executives of local governments in his State which he, in his discretion, determines will be affected by the proposed program. If any comment by such Governor is received by the Secretary at least fifteen days prior to submission to the Congress pursuant to such paragraph (3) and includes a request for any modification of such proposed program, the Secretary shall reply in writing, granting or denying such request in whole or in part, or granting such request in such modified form as the Secretary considers appropriate, and stating his reasons therefor. All such correspondence between the Secretary and the Governor of any affected State, together with any additional information and data relating thereto, shall accompany such proposed program when it is submitted to the Congress.

Leasing program, submittal to Congress.
Publication in Federal Register.

"(3) Within nine months after the date of enactment of this section, the Secretary shall submit a proposed leasing program to the Congress, the Attorney General, and the Governors of affected States, and shall publish such proposed program in the Federal Register. Each Governor shall, upon request, submit a copy of the proposed leasing program to the executive of any local government affected by the proposed program.

"(d)(1) Within ninety days after the date of publication of a proposed leasing program, the Attorney General may, after consultation with the Federal Trade Commission, submit comments on the anticipated effects of such proposed program upon competition. Any State, local government, or other person may submit comments and recommendations as to any aspect of such proposed program.

Leasing program, submittal to President and Congress.

"(2) At least sixty days prior to approving a proposed leasing program, the Secretary shall submit it to the President and the Congress, together with any comments received. Such submission shall indicate why any specific recommendation of the Attorney General or a State or local government was not accepted.

"(3) After the leasing program has been approved by the Secretary, or after eighteen months following the date of enactment of this section, whichever first occurs, no lease shall be issued unless it is for an area included in the approved leasing program and unless it contains provisions consistent with the approved leasing program, except that leasing shall be permitted to continue until such program is approved and for so long thereafter as such program is under judicial or administrative review pursuant to the provisions of this Act.

(continued)

Review.

"(e) The Secretary shall review the leasing program approved under this section at least once each year. He may revise and reapprove such program, at any time, and such revision and reapproval, except in the case of a revision which is not significant, shall be in the same manner as originally developed.

Regulations.

"(f) The Secretary shall, by regulation, establish procedures for—

"(1) receipt and consideration of nominations for any area to be offered for lease or to be excluded from leasing;

Public notice.

"(2) public notice of and participation in development of the leasing program;

"(3) review by State and local governments which may be impacted by the proposed leasing;

State and local governments, consultation.

"(4) periodic consultation with State and local governments, oil and gas lessees and permittees, and representatives of other individuals or organizations engaged in activity in or on the outer Continental Shelf, including those involved in fish and shellfish recovery, and recreational activities; and

"(5) consideration of the coastal zone management program being developed or administered by an affected coastal State pursuant to section 305 or section 306 of the Coastal Zone Management Act of 1972 (16 U.S.C. 1454, 1455).

Such procedures shall be applicable to any significant revision or reapproval of the leasing program.

Information, availability to Secretary.

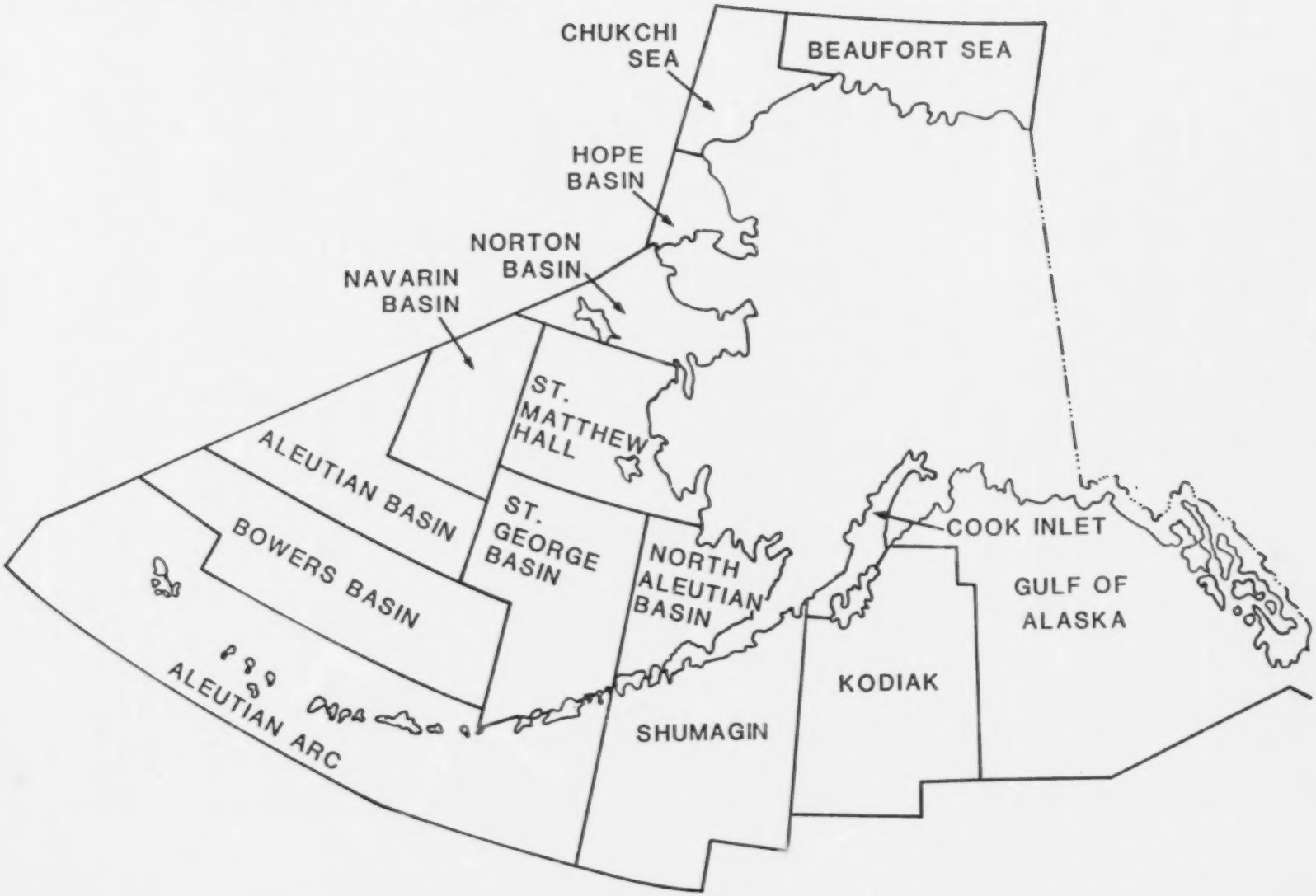
"(g) The Secretary may obtain from public sources, or purchase from private sources, any survey, data, report, or other information (including interpretations of such data, survey, report, or other information) which may be necessary to assist him in preparing any environmental impact statement and in making other evaluations required by this Act. Data of a classified nature provided to the Secretary under the provisions of this subsection shall remain confidential for such period of time as agreed to by the head of the department or agency from whom the information is requested. The Secretary shall maintain the confidentiality of all privileged or proprietary data or information for such period of time as is provided for in this Act, established by regulation, or agreed to by the parties.

"(h) The heads of all Federal departments and agencies shall provide the Secretary with any nonpriviledged or nonproprietary information he requests to assist him in preparing the leasing program and may provide the Secretary with any privileged or proprietary information he requests to assist him in preparing the leasing program. Privileged or proprietary information provided to the Secretary under the provisions of this subsection shall remain confidential for such period of time as agreed to by the head of the department or agency from whom the information is requested. In addition, the Secretary shall utilize the existing capabilities and resources of such Federal departments and agencies by appropriate agreement.

I.A.5 Maps Depicting the 26 Planning Areas of the OCS Pursuant to the Decision on the Draft Proposed Program

Map 1

OCS PLANNING AREAS



Map 2

I.B. Framework for Analysis: Planning for an Uncertain Future with Limited Information

Section 18(a) of the OCS Lands Act requires the Secretary to establish a 5-Year OCS Oil and Gas Leasing Program which

> . . . shall consist of a schedule of proposed lease sales indicating, as precisely as possible, the size, timing, and location of leasing activity which he determines will best meet national energy needs for the five-year period following its approval or reapproval.

Section 18(a) also requires the Secretary to consider a wide range of factors which affect or are affected by OCS oil and gas activities. On the basis of these considerations, the Secretary is to

> . . . select the timing and location of leasing, to the maximum extent practicable, so as to obtain a proper balance between the potential for environmental damage, the potential for the discovery of oil and gas, and the potential for adverse impact on the coastal zone [18(a)(3)].

This SID sets forth the information and analysis, both quantitative and qualitative, that has been developed to facilitate the Secretary's consideration and weighing of the potential costs and benefits that could result from leasing in each of the designated planning areas of the OCS. In addition, a final EIS on the new program will be prepared for the Secretary's decision on the third stage of the new program.

Past court rulings (California v. Watt (I) and (II)) have interpreted the provisions of section 18 as requiring the consideration and weighing of the costs and benefits of OCS oil and gas exploration, development, and production through an area-by-area comparison. The benefits are primarily the net economic and energy security benefits from the additional supply of energy to the country from production of OCS oil and gas, as well as the assessment of the oil and gas resources of the OCS. The costs to be considered are a variety of social costs such as potential damages to environmental resources or conflicts with other uses of marine resources. The social costs considered here are those which are generally not included in the economic costs which lessees pay for exploration, development, and production. An analysis of marine productivity and environmental sensitivity has been prepared to serve both as an input and as a complement to the analysis of social costs.

I.B.1. Potential Benefits and Costs

The new OCS Leasing Program is needed for 1987 through 1991 because of the net benefits that can be achieved through production of the oil and gas deposits that may be discovered on the portions of the OCS that are not leased as of 1986. The detailed analysis of benefits and costs and the summation of net social value appear in Part II of this SID.

The MMS estimates that as of January 1987, unleased undiscovered risked OCS oil and gas resources on leasable prospects will have a net economic value of between about $40 billion and about $92 billion ($1987), given a range of starting oil

prices of $19 to $29 per barrel (see Appendix F). The potential net benefits actually realized will depend on many factors: the oil and gas deposits in unleased acreage; their resource and economic characteristics; future conditions in world energy markets; the ways in which oil and gas companies respond in making investments in the OCS; and the actual effects of OCS oil and gas activities on the environment. The potential benefits from unleased acreage can also change in response to changes in the amount of unleased inventory, and the amount of resource information.

Since section 18 requires that the Secretary's selection of a leasing program be based on a consideration of the required technical analyses, it is important to indicate the limitations and implications of the assumptions made in those analyses. Appendix S describes this subject in detail.

A recognition of those limitations has important implications for the formulation of a leasing program, especially with respect to the issue of flexibility.

I.B.2. Limitations on Assessing the Effects of OCS Leasing

It is important in reviewing the materials in this document to recognize several limitations inherent in assessing the effects of OCS leasing and subsequent OCS activities. Because of such limitations, the information assembled for the Secretary's consideration required the development of new methods of analysis, the projection of numerous future events and conditions, and professional judgments on a wide variety of technical parameters.

Section 18(a)(2) speaks in terms of the "Timing and location of exploration, development, and production of oil and gas . . . ." One fundamental limitation on planning for those activities is that the Federal Government can only offer OCS oil and gas leases for purchase by private firms. In OCS lease sales, qualified bidders are given the opportunity to bid on the clearly defined and limited rights to explore, develop, and produce oil and gas which are set forth in the lease, the applicable stipulations, and the large body of applicable laws, regulations, and operating orders. Firms issued leases may then make the additional investments needed to seek, find, and produce oil and gas. The limits of predicting firms' investment decisions thus become, in turn, limits on predicting OCS activities.

The offering of OCS blocks for bids does not in itself cause bids to be submitted or leases to be issued on blocks which are bid upon. In fact, it is very difficult to predict the patterns of bidding and leasing which will occur at a given lease sale. For oil and gas exploration, firms have alternatives to U.S. OCS oil and gas leasing. Firms can lease in the U.S. and foreign onshore markets and in the State and foreign offshore markets. Additionally, the issuance of leases does not necessarily cause investments in exploratory drilling and development. Such investments occur in response to continually changing perceptions about the potential payoffs that might result. In fact, many leased blocks are not drilled because of information gleaned after leasing.

All of the subsequent effects--both costs and benefits--of OCS exploration, development, and production depend upon the patterns of leasing and investment in combination with the the actual location, quantity, and value of the hydrocarbons discovered--if any. Those quantities and values, in turn, can only be estimated in probabilistic terms in advance of lease sales and exploratory investments. Further, discovery of new fields and the amount discovered often bear little relation to the level of leasing and exploration costs, especially in frontier areas. Thus, the very nature of the activity of offering leases and awaiting the results of subsequent investment and exploratory drilling severely limits the precision possible in the prediction of the resultant effects.

I.B.3 Recognition of the Limitations of the Technical Analyses

The precision with which future OCS oil and gas activities can be planned is further limited by the kinds of considerations on which the 5-year program is to be based pursuant to section 18 as interpreted by the court. The factors which section 18(a)(2) requires the Secretary to consider and the balancing which section 18(a)(3) requires the Secretary to perform are the legal bases for the technical analyses which appear in Part II.B of this document. These analyses are, in turn, a key basis for the development of the 5-year program. Notwithstanding the technical aspects of those analyses, the exercise of judgment not reducible to technique is a crucial element in every one of them. This issue is examined in greater detail in Appendix S.

II. Section 18 Analyses

A. National Energy Needs and the OCS Oil and Gas Leasing Program

Section 18(a) of the OCS Lands Act mandates that the OCS Oil and Gas Leasing Program prepared by the Secretary shall be one "which he determines will best meet national energy needs for the five-year period following its approval or reapproval . . . ." The provision that the 5-year program be keyed to national energy needs reflects the first purpose of the OCS Lands Act Amendments:

> Section 102. The purposes of this Act are to--
>
> (1) establish policies and procedures for managing the oil and natural gas resources of the Outer Continental Shelf which are intended to result in expedited exploration and development of the Outer Continental Shelf in order to achieve national economic and energy policy goals, assure national security, reduce dependence on foreign sources, and maintain a favorable balance of payments in world trade. . . .

It is also relevant to note here that the Mining and Minerals Policy Act of 1970 (30 U.S.C. 21a) provides that:

> The Congress declares that it is the continuing policy of the Federal Government in the national interest to foster and encourage private enterprise in
>
> (1) the development of economically sound and stable domestic mining, minerals [defined to include oil and gas], metal and mineral reclamation industries, [and]
>
> (2) the orderly and economic development of domestic mineral resources, reserves, and reclamation of metals and minerals to help assure satisfaction of industrial, security, and environmental needs . . . .

National Economic and Energy Goals

National economic and energy goals are closely linked. The linchpin is our Nation's continuing dependence on imported oil. In 1984, the United States continued to import about 30 percent of the crude oil which it consumed. The actual disruptions in oil imports which the United States has suffered make clear the nexus of foreign/national security policy and economic policy with respect to the oil import issue. The disruptions of 1973 and 1979 both arose in the international arena and both had substantial recessionary effects on the United States economy. Thus, planning for the future involves consideration of both the national economy and the foreign/national security policy aspects of the oil import issue.

The most recent National Energy Policy Plan, issued by the Department of Energy in October 1983, recognizes this connection. The National Energy Policy Plan sets forth as the general goal of national energy policy the fostering of an adequate supply of energy at reasonable cost. Adequate supply is explained

in the Plan as requiring "a flexible energy system that avoids undue dependence on any single source of supply, foreign or domestic, and thereby contributes to national security. . . [and] further implies freedom of choice about the mix and measure of energy needs to meet our industrial, commercial, and personal requirements." The National Energy Policy Plan recognizes OCS leasing as an important element in the Nation's effort to pursue the assurance of long-term energy supplies.

In examining the way in which OCS oil and gas production can help meet national energy needs, it is appropriate to review the following topics: the role of OCS oil and gas in the United States economy; the current and projected United States demand for energy in general and oil and gas in particular; the current and projected U.S. supply of oil and gas; the prospect for continued dependence on oil imports; the domestic and foreign policy implications of such continued dependence; and the role of OCS leasing in reducing that dependence. The first four points are discussed at length in Appendix F. The summary below reviews those topics and also discusses the last two points.

Oil and gas from the OCS are important resources because they contribute to the production of a substantial volume and variety of goods and services that the American people, as consumers, value.

In addition, OCS oil and gas produced at a cost lower than prices set by the world oil market contribute to the Nation's economic productivity. The greater the amount of OCS oil and gas produced at costs less than world oil prices, the greater is that contribution. Economic productivity is increased by allowing firms a range and sequence of opportunities that will encourage an economically efficient path of investments in OCS exploration and production. In general, this will increase the amount of oil and gas discovered and produced, thus benefiting the economy.

Domestic Energy Supply and Demand

In 1984, the United States consumed 73.73 quadrillion British Thermal Units (Btu) of energy. Oil and gas constituted about two-thirds of that amount. /1

The Nation's production of oil and natural gas liquids peaked in 1970 and dry natural gas production peaked in 1973. The decline in oil production since 1970 reflects the depletion of older fields without the discovery of new reserves sufficient to replace the oil produced. The decline has been cushioned by production from the giant Prudhoe Bay oil field. If it were not for that field, U.S. production would have plummeted nearly 30 percent over the past decade instead of falling by only 5 percent.

The U.S. Department of Energy has projected that total U.S. domestic oil production will decline 1.0 to 1.5 percent per year for the next 10 to 15 years. Total natural gas production is expected to drop also, but more slowly through 1990. /2

/1 U.S. Department of Energy, Annual Energy Review 1984, April 1985, Table 1.
/2 DOE, Energy Projections to the Year 2010, October 1983.

United States Dependence on Imported Oil

Relative to the United States supply of energy from other sources, a substantial percentage of our oil supply is imported. In the 1970 to 1980 timeframe, domestic oil and gas production represented approximately 50 to 60 percent of the total energy supplied to the U.S. economy; imports of oil and gas supplied approximately 11 to 18.5 percent. U.S. Department of Energy projections to the year 2000 indicate that imported oil and gas will continue to supply an estimated 14.6 percent of our total domestic energy in the year 2000. (Imported gas constitutes only 3 percent of the 14.6 percent.) Although this percentage has decreased from a high of 18.5 percent in 1975 and 1980, in absolute terms, imports are projected to increase to 13.4 quad Btu in 1990 (a level which they were at in 1975) and are projected subsequently to rise to 13.6 quad Btu in the year 2000. Domestic production of oil is projected to decrease from 19.5 quad Btu to 17.4 quad Btu in the 1985-2000 timeframe. /3

Potential Contribution of OCS Leasing and Production

Leasing and exploration of OCS oil and gas resources provides an important way of helping to slow the long-term decline of proved domestic hydrocarbons reserves. The hydrocarbons produced from the OCS in Fiscal Year 1984 represented about 12 percent of domestic production of oil and about 25 percent of domestic natural gas production.

In addition to benefiting from the use of domestic oil and gas to fuel the general level of economic activity, the American people benefit in their roles as owners, through the Federal Government, of the resources of the OCS. As owners of OCS oil and gas, the American people benefit from production of any OCS resource costing less to find and produce than the price at which it can be sold (see Appendix F.)

Aside from the effects of a potential supply disruption (discussed below), the importation of foreign oil reduces the economic well-being of the American people. In 1984, the gross cost of importing crude oil and refined petroleum products amounted to over $59 billion. Those imports accounted for almost 50 percent of our balance of trade deficit in that year.

The recent growth in U.S. GNP of about 6.8 percent for 1984 resulted in U.S. oil demand exceeding that of 1983 by about 3.5 percent. /4 The lag in demand for oil is caused in large part by substitution and conservation effects which have yet to run their course.

Means of Pursuing National Energy and Economic Goals

One way to view the national security aspect of OCS production is to see its relation to national economic goals. Disruption of supplies of oil from abroad causes disruption in the production and consumption of goods and reduces economic productivity. This causes decreases in income and increases in consumer price levels. The 1984 Office of Technology Assessment (OTA) Report, U.S. Vulnerability to an Oil Import Curtailment, estimates that a

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/3 Ibid., Table 3-4. Also see Appendix F.

/4 DRI Inc., Energy Review, Volume VIII, No. 4, Winter 1984-1985.

significant disruption of oil imports could result in a reduction of the Gross National Product of 3.5 to 6.2 percent, accompanied by increased unemployment of 1.7 to 2.3 percent (pp. 146-147; see also Appendix F of this SID).

However, most measures to assure that our national energy needs will be met have economic costs. Thus, the economy needs to adjust continually, balancing the costs of those measures against their economic benefits. The OCS leasing program can help to meet both national energy and economic needs by helping to reduce oil imports and providing a source of domestic supply in periods of future disruptions and higher prices.

On the one hand, it is possible that world oil prices in the 1990's will be sufficiently low to render uneconomic many of the oil and gas prospects remaining to be leased on the OCS. On the other hand, oil prices may not decline or remain low for very long. Higher oil prices would increase the number of good prospects for discovery of oil and gas on the OCS. The rate of leasing and investment in exploration would be higher. The resulting production would help the economy use less high cost imported oil, thus increasing its economic productivity (see Part II.B.1).

Over the long run, OCS oil and gas resources will make a contribution to economic productivity if investment and production decisions can adjust quickly to changing world energy markets. An OCS leasing program can help meet the Nation's energy and economic needs by providing opportunities for investments in exploration and development when they are economically timely. Such a program would allow rapid increases in leasing and investment if world oil prices were to increase to higher plateaus while allowing a lower investment and production rate during periods of lower prices. Allowing a quicker shift from imported to domestic oil when oil prices increase reduces the economic costs of abrupt changes in the world oil supply. Ensuring such flexibility in the OCS leasing program can contribute to meeting our national energy needs--but the long lead time for the development of OCS oil and gas resources requires that flexibility be insured throughout the program and well in advance of emergency situations. This point is discussed further at the end of this section.

National Security Concerns Relevant to OCS Leasing

National security considerations clearly point to the need for such flexibility in the OCS leasing program. The continuing dependence of the United States on oil imports for a substantial part of our oil consumption creates a number of national security concerns.

First, the potential for a supply disruption imposes political limits on the flexibility of our foreign/national security policy, including our ability to respond to foreign security threats.

Second, our dependence on foreign nations for so essential a commodity as oil creates the potential for the United States to be drawn into dangerous political and military situations involving those nations.

Third, dependence on oil imports entails dependence on extended supply lines (tanker routes) which present a target for attack and thus add to our defense burden. This added defense burden involves both the deterrence of attacks as well as actual defense in the event of an attack.

Fourth, many other nations, including our allies, are faced with the same set of problems. The restraints on them indirectly but effectively pose further limits on our own national security flexibility. Thus, any improvement in our ability to assist them in meeting their energy needs in turn improves our ability to pursue our own foreign policy/national security goals. The 1983 National Energy Policy Plan, underlines this last point by noting that:

> The overriding concern of our allies to reduce their dependency on imported oil has led to growing reliance on natural gas from the Soviet Union, a new source of vulnerability and concern to our collective energy security and to fundamental United States national security interests.

Fifth, if there were a world oil shortfall, all of our suppliers, including non-OPEC suppliers, might reduce oil shipments to us in order to honor all of their export contracts equitably. Thus, our oil import vulnerability is not limited to our reduced amount of OPEC imports.

Sixth, key weapons systems in the Nation's current arsenal and under development for future use are designed to use liquid hydrocarbon fuel. In Fiscal Year 1983, the armed forces used over 177 million barrels of oil, which was the equivalent of over 58% of OCS oil production in that year. The most secure sources of supply for such fuel are, clearly, domestic sources. This consideration is reflected in section 12(b) of the original OCS Lands Act:

> In time of war, or when the President shall so prescribe, the United States shall have the right of first refusal to purchase at the market price all or any portion of any mineral [including oil and gas] produced from the outer Continental Shelf.

OCS Leasing in Perspective

The question of how to control our reliance on imported oil over coming decades can be seen as a question of balancing the economic productivity gained by using cheaper imported oil during times when world prices are lower against the potential costs of supply disruptions. Furthermore, it is quite possible that the total U.S. endowment of oil and gas resources will not be sufficient in amount and low enough in cost for production to keep pace with demand through the coming decades during which relatively low cost reserves in the Middle East and elsewhere are depleted. Nonetheless, the OCS oil and gas leasing program can continue to make a significant contribution to meeting national energy needs.

In order to understand the contribution which OCS oil and gas leasing can make to long-term energy supplies, it is useful to review some of the other efforts and proposals which have been made to reduce our vulnerability to oil supply disruptions. While these approaches have a great deal to offer, they nonetheless have limitations which call for the kind of contribution which the OCS leasing program can make to the pursuit of national energy goals. These approaches include: the creation of the Strategic Petroleum Reserve; the diversification of supply; the concept of developing an oil replacement capability; and reliance on alternative energy sources.

--The Strategic Petroleum Reserve

At its current level of about 450 million barrels, the Strategic Petroleum Reserve (SPR) can substitute for about 141 days of oil imported at current rates of supply and demand. The SPR's greatest usefulness is in blunting supply cuts and the resultant price spikes in the short-run. In the case of a disastrous reduction of oil supply over a sustained period, the SPR--even if filled to its ultimate capacity, once envisioned as one billion barrels, but now set at three-quarters of a billion barrels--would prove of limited usefulness. While such a disaster is not on the immediate horizon, it cannot be dismissed as a possibility. After all, the West's supply of oil is disproportionately dependent on the oil production of a handful of nations whose political future cannot be said to be assured.

--Diversification of Sources of Supply

The diversification of sources of supply which the United States and, to a lesser extent, its allies, have been able to achieve presents the prospect of significant protection against the disruption of oil supplies from the Middle East. Yet its potential to insulate the United States from vulnerability to such disruptions also has limits. First, it could well be that during a significant supply disruption, remaining suppliers might ration the added supplies which they are capable of providing so as to treat all of their customers equitably. Second, under the auspices of the International Energy Agency, the United States and many of its allies are obliged to share oil in the event of a major disruption of oil supplies. That sharing system has never been put to a real test, however. Furthermore, by relying on other nations to share their limited supplies with us in order to meet our great oil consumption demands, we could well strain our relations with the nations on which we relied for such sharing and with those with whom we would be competing for supplies. Thus, the less we need to depend on such sharing agreements, the better off we would be in terms of both certainty of supply and relations with other nations.

--Oil Replacement Capability

Another useful concept is the development of oil replacement capacity--i.e., the capacity to deploy technologies and strategies which minimize the effects of a long-term oil supply shortfall. Again, however, an oil replacement strategy does not exhaust the range of useful responses to the problem posed by our vulnerability to the disruption of oil supplies from abroad. Increased domestic supplies of hydrocarbon fuel still have an important role to play in responding to an oil import shortfall. Indeed, the OTA study on oil replacement (cited above) includes a discussion of the desirability of the deregulation of the price of natural gas so as to increase its supply (at pp. 27-28, 30).

--Alternative Energy Sources

Several energy sources other than oil and gas are expected to be used in this Nation during the remainder of this century and the first quarter of the next. These sources include coal, hydroelectric, nuclear, oil shale, tar sands, and geothermal energy. Nonconventional forms such as wind, solar, and converted biomass energy may also be used to a much lesser extent. Coal will probably be the most heavily used alternative source of energy, followed, in order, by hydroelectric, nuclear, and geothermal energy (see Appendix F).

Notwithstanding use of the several alternative forms of energy discussed above, the U.S. Department of Energy projects that about 38.7 percent of the Nation's energy demand in the year 2010 will be met by oil and gas. Nearly 40 percent of this needed oil and gas is projected to be imported. /5

By providing opportunities to increase our domestic supplies of oil and gas, the OCS leasing program provides an important--and less costly--contribution to energy security, in addition to the three strategies described above. Leasing of the OCS also provides supplies which are available over the long-term.

Information Benefits

Information benefits are another type of benefit from OCS leasing, exploration, and development. Information benefits are the benefits to the Nation--beyond economic benefits--of added information about the extent of oil and gas resources on the OCS.

The generation of information benefits is one of the specified purposes of the 1978 OCS Lands Act Amendments. Section 102(9) of the Amendments states that one of the purposes of that act is to "insure that the extent of oil and natural gas resources of the Outer Continental Shelf is assessed at the earliest practicable time." It is of the nature of oil and gas resource assessment that only drilling can confirm the existence and size of a deposit. On the OCS, drilling for oil and gas is essentially tied to leasing and thus to the 5-year leasing program.

As in the case of production, the contribution to the overall picture made by any particular lease may be small, but without the small pieces, the overall picture cannot be created. Of all the small pieces, the first well in an area generally provides the most information. Where the existence of commercial accumulations of hydrocarbons has not been demonstrated, there is usually a high degree of dependence among estimates of resources on prospects. In these cases, the information generated by exploration on a given prospect generally sheds a great deal of light on the resource potential of the surrounding acreage. /6

The estimated size of the resource base of the OCS has major implications for the country's energy and national security policies. Clearly, if U.S. oil and gas resources were very great or very limited, the implications for our foreign policy would be very different. While the resources potential of the U.S. is estimated to be somewhere between those two extremes, it is best for the Nation to know just where it stands.

The Department of State is also particularly concerned with estimates of OCS oil and gas resources regarding international boundary negotiations with neighboring nation-states concerning jurisdiction over those resources. Such negotiations are ongoing concerning several planning areas.

The Department of Energy has made explicit use of estimates of undiscovered OCS oil and gas resources in developing its report, Replacement Costs of Domestic Crude Oil (1985), which is designed to aid in planning for fossil energy research and development.

/5 U.S. Department of Energy, Energy Projections to the Year 2010, October 1983, Table 3-5.

/6 See, for example, MMS, Estimates of Undiscovered, Economically Recoverable Oil and Gas Resources for the OCS as of July 1984, (OCS Report MMS 85-0012), p. 22.

The OTA Report on Oil and Technologies for the Arctic and Deepwater (May 1985) provides a useful summary of this issue in stating that

> If Congress wishes to pursue the objectives of the OCS Lands Act, it is important that the oil and gas industry have access to Federal offshore lands to more accurately determine the resource potential of frontier areas. A "second-round" leasing strategy may also be needed to assess the extent of smaller offshore reservoirs that could cumulatively contribute to the Nation's energy security [p. 5].

The OTA report also states that

> Accurate knowledge of the resource potential of the Nation's offshore areas is critical to overall energy planning and to making decisions about the offshore leasing program and alternative energy programs [p. 11].

That report highlighted the decline from previous levels of the most recent MMS OCS estimates of oil and gas resources offshore Alaska and in the Atlantic and examined its implications for U.S. energy policy. Some interpretations of the latest data have focused on that decline as supporting policies of energy conservation and alternative energy research. Others have gone so far as to suggest that somehow the new data means that OCS leasing, exploration, and development are not worth pursuing--even for the substantial economically recoverable resources which are still estimated to exist. The Department of the Interior--complementing the first view and opposing the second--emphasizes the substantial contribution which OCS leasing, exploration, and development will continue to make in terms of net social value, national security, and information benefits. For only through actual exploratory drilling can the truth be determined about the presence of oil and gas.

The Long-Term Role of OCS Leasing and Production

The long-term character of OCS production is matched by the long-term character of the planning and development which precedes production. Holding an OCS lease sale is the fruit of years of public and private planning. Once OCS acreage is leased, initial production can take another 5 to 15 years. Thus, the next leasing program needs to be considered as a step in meeting domestic supply requirements of the late 1990's and the first quarter of the 21st century.

The consequence of the long-term character of OCS development is that decisionmaking about it should not be guided by the trend of the day. Leasing of the OCS is unusually vulnerable to short-term phenomena which can disrupt it in ways that can be made up only at substantial cost in time and opportunity. Public policy concerning OCS leasing should, therefore, be guided by a steady, long-term perspective on the potential seriousness of the risks involved in oil supply disruptions, their unpredictability, and the long lead-times necessary to make OCS production available for use. Without the assurance that OCS leasing policy will remain firm, industry would likely be reluctant to invest the huge sums required to develop OCS resources.

What this means can be illustrated by examining the argument that potential oil and gas resources be withdrawn from leasing in certain areas and saved as a "reserve" for use in a national emergency. In practice, however, the only way in which potential oil and gas resources can constitute a useful reserve in case of an emergency is if they are not withdrawn from the normal course of exploration and development through which drilling can locate and delineate the reserve deposit and the necessary production infrastructure can be put in place.

II.B. Planning Area Analyses

Pursuant to California v. Watt (II), the following comparisons of planning areas provide a basis for considering whether there is any categorical impediment to OCS leasing in any planning area. These analyses also provide input for the discussion of the equitable sharing of developmental benefits and environmental risks in Part II.C. and the discussion of balancing in Part II.D.

The July 1984 request for comments on the development of the new program divided the entire OCS into 24 planning areas. The March 1985 Draft Proposed Program divided the OCS into 26 planning areas. First, it reconfigured the planning areas offshore California from two (Southern California and Central/Northern California) to three (Southern California, Central California, and Northern California). Second, the southern part of the South Atlantic planning area was made the Straits of Florida planning area. This reconfiguration is incorporated in the section 18 analyses and the schedule options for Secretarial decision on the Proposed Program.

The planning areas analyzed are discussed in the Federal Register Notice describing the Draft Proposed Program (see Appendix M). At this Proposed Program stage, four planning areas (Aleutian Basin, Bowers Basin, St. Matthew-Hall, and Aleutian Arc) have been deleted from further consideration because they were estimated to contain negligible resources.

For this SID for the Proposed Program, the following refined section 18 analyses have been prepared. A final version of these analyses will be prepared for the decision on the Proposed Final Program.

To provide for comparability of the oil and gas resource value estimates among the planning areas the following general approach was employed:

1. All OCS oil and gas resources estimated to be worth acquiring by private industry under specified economic conditions were assumed to be leased as of January 1987 in each planning area. Exploration, development, and production would then follow according to a scenario characteristic of the planning area. The results for starting prices of oil at $19 and $29 per barrel are presented in Table 2.

2. Net present value estimates were calculated for a risked mean resource estimate and an economic base case scenario assuming a July 1984 starting price of oil of $24 a barrel, a 1-percent real annual price growth rate, and an 8 percent discount rate. Sensitivity analyses were conducted around the risked mean resource estimate

which allowed for variations in the base case assumptions for the starting price of oil, the annual average growth in oil prices, and the discount rate. The results for starting prices of oil at $19 and $29 per barrel are presented in Table 3. The remaining sensitivity calculations are included in Appendix F.

Section 18 analyses have been performed on a planning area basis. It is important to note that the MMS aggregate estimates of resources and net economic value, as well as industry rankings for various planning areas, do not distinguish between areas in which high-valued resources and industry interest are concentrated in a portion of a planning area and those in which low-valued resources and industry interest are widely distributed throughout the planning area. It should also be noted that the presale process provides ways of adjusting the size of the area offered in lease sales in order to accommodate these differences among areas. The presale process is discussed further in Part III and Appendix P.

II.B.1. Estimates of Hydrocarbon Resources and Economic Benefits

To facilitate the Secretary's consideration of the potential for oil and gas discovery and the resulting contribution to the Nation's energy and economic needs that could result from leasing in each of the OCS planning areas, estimates of the oil and gas resources and their net economic values were made. Two major improvements were made over the estimating procedures used in the 1982 program formulation:

1. The estimation of oil and gas resources in each area was based upon an extensive evaluation of an inventory of identified unleased prospects rather than upon calculations employing the aggregate volumes of oil and gas likely to be found (used in the 1982 analysis).

2. The estimates of resources and net economic values in each area were based upon a wider range of characteristics (e.g., variation in prices and discount rates) that influence the economics of various prospects than was the case in the 1982 analysis.

These improvements make it possible for the Secretary to consider in more detail the aspects of each planning area that characterize its potential for yielding oil and gas discoveries and economic benefits. The economic measure

of the benefits which the Nation can realize from OCS oil and gas exploration and development is the net economic value of the hydrocarbon resources. The net economic value of an oil and gas deposit measures the difference between the revenues from the sale of oil and gas produced and the costs of exploration, development, production, and transportation--both costs and revenues being appropriately discounted to present value. Estimates of net economic value take into account the probabilities of the various events that affect the resource and economic outcomes of investment in an unexplored prospect. Net economic value is also a measure of the benefits to the economy in the form of cash bonuses, royalties or profit share payments, rental fees, taxes, and after-tax business profits. The sum of the amounts expected to be captured in these forms is equal to the difference between expected production revenues and costs (see Appendix F).

a. Hydrocarbon Resources

Three different categories of hydrocarbon resource estimates have been made for each of the planning areas of the OCS:

1. conditional economically recoverable oil and gas resources;
2. risked economically recoverable oil and gas resources; and
3. leasable oil and gas resources.

Table 1 (derived from Table 5 of Appendix F) contains the range of conditional resource estimates of each of the OCS planning areas, indicating the great variability in their magnitude. Due to the inherent uncertainty of estimating undiscovered resources, especially in frontier areas, a range of estimates is shown in Table 1 of the SID. The 95 percent case for conditional estimates of both oil and gas reflects a low case where there is 95 percent probability of that amount or more occurring. The high case reflects a 5 percent probability of that amount or more occurring. A conditional mean estimate is the average amount you would expect to find if at least one of the prospects in the area contained economically recoverable accumulations of hydrocarbons and if all of the prospects modelled were drilled. The conditional resource estimates assume that hydrocarbons will be present in some of the planning area prospects. They do not take into account the possibility that the area may not be hydrocarbon prone; this consideration is taken into account in determining the risked economically recoverable resources in a planning area (see Table 6 of Appendix F).

For each of the 2400 geologic prospects identified by MMS on the OCS, a resource estimating model generated a projection of the risked economically recoverable resources. Procedurally, the model first generated a conditional distribution indicating the probability of finding different amounts of commercially producible and nonproducible hydrocarbons given that at least some of the identified prospects contained hydrocarbons.

Table 1

Ranges of Conditional Estimates of Unleased Undiscovered
Economically Recoverable Oil and Gas Resources as of March 1985 /1

Planning Area	Conditional Oil (BBO) /2			Conditional Gas (TCF) /3		
	95% Case	Mean Case	5% Case	95% Case	Mean Case	5% Case
Central Gulf of Mexico	.95	2.66	4.97	7.57	20.64	36.53
Western Gulf of Mexico	.45	1.69	3.31	7.23	22.61	41.05
Eastern Gulf of Mexico	.03	.36	1.48	.04	1.63	8.88
Southern California	.61	1.26	2.08	0.97	1.93	2.98
Northern California	.15	.42	.76	1.17	1.86	2.48
Central California	.18	.56	1.01	.29	.79	1.38
Washington-Oregon	.04	.18	.54	2.20	3.26	3.62
South Atlantic	.34	.82	1.46	6.30	15.45	27.56
Mid-Atlantic	.07	.24	.51	1.39	4.21	8.18
North Atlantic	.10	.26	.43	1.98	5.06	9.03
Straits of Florida	.01	.04	.12	.20	1.04	3.79
Navarin Basin	1.81	3.28	5.09	2.34	4.26	6.75
Beaufort Sea	.11	.65	1.66	.52	2.98	6.39
St. George Basin	.37	1.12	1.98	3.42	9.24	18.04
Chukchi Sea	.96	2.68	4.88	5.06	15.10	27.71
Gulf of Alaska	.12	.49	.86	1.60	8.00	18.26
North Aleutian Basin	.08	.36	.76	.56	2.62	5.25
Norton Basin	.05	.28	1.02	.31	1.55	4.26
Kodiak	.04	.15	.26	.58	2.92	7.13
Hope Basin	.13	.17	.40	.53	1.81	4.12
Shumagin	.05	.05	.09	.49	1.42	2.65
Cook Inlet	.03	.18	.40	.04	.32	.69

/1 See Appendix F, Table 5
/2 Billions of barrels of oil
/3 Trillion cubic feet

Setting commercially nonproducible amounts of resources at zero with its associated probability, the mean of this revised distribution of producible resources was obtained. When this mean producible amount was multiplied by the marginal probability that the prospect contained hydrocarbons, the risked economically recoverable resources for the prospect was calculated.

The term economically recoverable oil and gas resources, as used throughout this analysis, is a measure of those resources found in sufficient quantities such that the revenues produced cover the costs of development and production, royalties and taxes, while allowing for a normal rate of return. The estimates of both conditional and risked economically recoverable resources do not take into account costs incurred in searching for oil and gas, primarily exploration expenses. As a consequence, in estimating at the time of sale the net economic value of prospects containing positive amounts of economically recoverable resources, some prospects were found not only to have negative private values but also negative net economic values as well. Such prospects would not receive a bid based on this assessment of the present value. In order to provide the Secretary with aggregate estimates of oil and gas resources and net economic values likely to be influenced by decisions relating to the next 5-Year Program, a new category of resources called leasable resources has been defined.

Leasable resources are estimated as follows. An assessment is conducted of each prospect to determine its (risked) economic value at the time of sale to both the lessee and to the Nation as a whole. If the private value (after tax net present value), as estimated by MMS, is found to be greater than zero, then the economically recoverable resources associated with the prospect are considered leasable. If the private value of the prospect is zero or less, then the entire amount of the prospect's economically recoverable resources are deemed to be unleasable at the time of sale for the given economic assumptions.

Thus, the estimate of leasable resources in a planning area is the sum of economically recoverable resources associated with prospects calculated by MMS to be worth acquiring, i.e., they have positive private values. The estimates of leasable resources as of January 1987, are somewhat understated because resources which may become leasable after January 1987, due to real oil price growth, are not factored into the estimates.

The resource estimates were prepared using assumptions (prices, price growth, discount rates, etc.) developed for the 5-Year Program analyses. These estimates may not reflect the economic parameters and assumptions used for upcoming sale specific analyses; and therefore should not be applied to any sales scheduled prior to the beginning of the new 5-Year Program (January 1987).

Table 2 contains the estimates of leasable resources for each of the planning areas for prices reflecting a low case of $19 per barrel, and a

Table 2

Variation in Risked Estimates of Unleased Undiscovered /1
Oil and Gas Resources Projected to be in
Leasable Prospects ("Leasable Resources") as of January 1987 /2
(from $19 to $29 per barrel 1984 starting prices)

Planning Area /3	Estimated Risked Oil and Gas Resources (Millions of barrels of oil equivalent (BOE)) Starting Prices @ $19/bbl	@ $29/bbl
Central Gulf of Mexico	4,603	4,662
Western Gulf of Mexico	4,491	4,630
Southern California	1,046	1,264
Navarin Basin	178	785
South Atlantic	392	730
Eastern Gulf of Mexico	331	470
Northern California	281	414
Central California	320	405
Beaufort Sea /4	*	308
Mid-Atlantic	88	184
St. George Basin	*	160
Washington-Oregon	46	56
North Atlantic	35	74
Straits of Florida	6	6
Chukchi Sea /4	*	400
Gulf of Alaska	*	28
North Aleutian Basin	*	16
Norton Basin	*	12
Kodiak	*	*
Hope Basin	*	*
Shumagin	*	*
Cook Inlet	*	*

* Negligible (estimated to be less than 0.5 million BOE).

/1 Risked oil and gas resource estimates are obtained by multiplying the conditional mean resource estimate by the marginal probability of the presence of commercial accumulations of hydrocarbons (see Appendix F).

/2 Resource estimates exclude those resources expected to be leased in upcoming sales scheduled to be held before the start of this 5-year program. Leasable resources are those which, prior to exploration, are expected to bring positive net benefits to the lessees after deducting royalties, rentals, and taxes. After adjusting for transportation costs and crude oil quality expected in each OCS region, January 1987 landed BOE price estimates were computed assuming a 5 percent annual inflation rate and a real oil price increase of 1 percent per year. An annual real discount rate of 8 percent was used to determine 1987 discounted value of all costs and benefits. All calculations of net economic value and social costs in this SID and its appendices were based on these assumptions unless otherwise specified (see Appendix F).

/3 The planning areas are ordered by "leasable resources" at $24/bbl.

/4 Calculations exclude Beaufort Sea and Chukchi Sea natural gas (see Appendix F).

high case of $29 per barrel--as applied to the risked mean resource estimates.

Resource estimates were revised to take into account sales appearing on the current schedule through January 1987. As Table 2 shows, the Central and Western Gulf of Mexico areas are estimated to have more resource potential in acreage unleased as of 1987 than all the other planning areas combined. The Southern California planning area ranks next with considerably more resources than any other planning area. Significant changes in the resources occur in certain frontier planning areas as the starting oil price assumption moves from $19 to $29 per barrel of oil because of the high development costs in these areas.

Past and projected leasing in the 1982-1987 period, unpromising exploration results in many areas to date, and lower price expectations have substantially reduced the resource potential remaining to be leased, as compared to the situation anticipated in 1982. This is especially the case in areas previously believed to have high potential, such as the Beaufort Sea and North and Mid-Atlantic areas which were ranked relatively higher in the 1982-1986 program. Most of these areas could show increased potential assuming higher price expectations, positive results from exploration, or additional seismic data evaluation. This is also true of areas where there has been little or no exploration.

b. Economic Benefits

For each planning area, estimates were made of the net economic value of the prospects containing leasable resources. For comparative purposes on a planning area basis, these estimates were based on the assumption that all leasable prospects were acquired by private industry at the beginning of 1987 and subsequently explored, developed, and produced over time periods typical of each area. This approach was upheld by the court in California v. Watt (II) (see Appendix F).

The base case estimates of net economic value for each of the planning areas' leasable oil and gas resources assumed a $24 per barrel starting price of oil with a sensitivity of plus and minus $5 per barrel, that is, a variation from $19 to $29 per barrel. Price sensitivity results were incorporated into the net economic value estimates to reflect the great uncertainty in projecting future oil prices. This sensitivity analysis shows how the potential benefits of OCS development depend upon future prices. For example, the $19 and $29 price cases in 1984 correspond to values of $27 and $41 per barrel in year 2010 (as expressed in 1987 dollars).

It should be noted that this analysis reflects the sensitivity of net economic value to changes in the price assumptions only, and does not incorporate the affects of geologic and economic resource uncertainty conveyed by the ranges of resource estimates. The SID does not provide ranges which reflect both sources of uncertainty combined. It should also be noted that while the variation in net economic value is keyed to alternative starting oil prices, the resulting variation of net economic value is a kind of surrogate for other sensitivity measures which have not been performed (e.g., with respect to resource estimates and the variability of oil and gas prices within the range depicted in Figure 1).

The $19 and $29 per barrel starting prices of oil are expressed in July 1984 dollars, which was when this analysis began. It was subsequently adjusted to January 1987 price levels by assuming a 1 percent real annual increase in the price of oil and a 5 percent inflation rate applied for 2 years beginning in January 1985. After January 1987, prices were assumed to increase at a 1 percent real annual rate of growth. Sensitivity analyses of the net economic value estimates were conducted to demonstrate the variability of the estimates to changes in the price growth rate (at zero percent and 2 percent annually) and at a 6 percent to 8 percent discount rate assumption (see Table 13 of Appendix F). As can be seen from the sensitivity analysis, the variation in net economic value estimates is even greater when considering these further changes in assumptions.

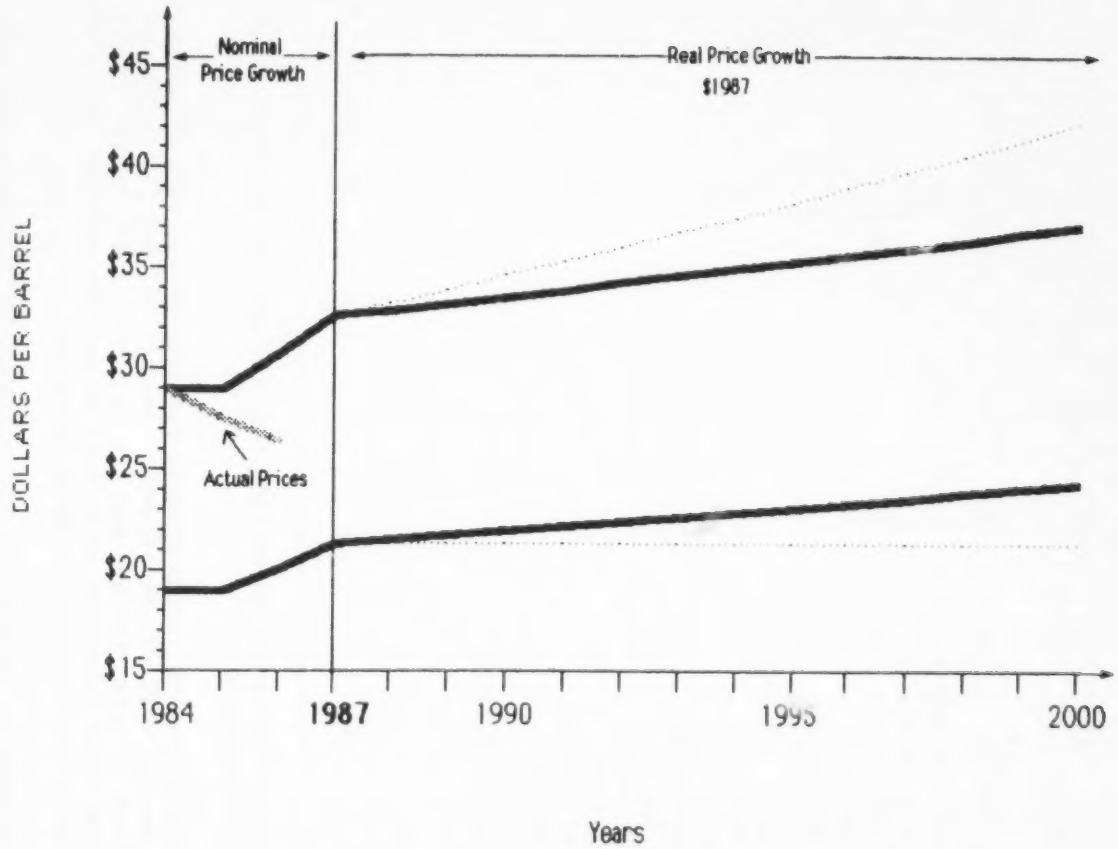
Figure 1 graphically approximates the variation in prices which were considered in the development of the leasable resources and net economic value estimates (limited to the year 2000 for ease of display). As can be seen from this graph, actual prices through July 1985 are declining. As explained in Appendix F, this is one reason that the variation in price estimates were adjusted downward, from $34 to $24 per barrel in the Draft Proposed Program to $29 to $19 per barrel for this Proposed Program. The high and low price cases considered for the Proposed Program (depicted by the bold lines in Figure 1) were selected to cover the range of oil prices which are projected to exist during the time of exploration and development of resources expected to be leased during the 5-Year Program of 1987-1991.

Table 3 shows the variation of net economic value estimates (1987 dollars) indicating the great variability in the values over a $10 price spread, Table 5 shows these same results on a per barrel basis. The high case estimates for certain Alaska areas in Table 3 indicate the profitability of oil and gas with the higher price scenario. The sum of the net economic value estimates show a potential increase in benefit to the economy of $50 billion as one moves from the $19 per barrel case to the $29 per barrel case.

In addition to the total net economic value estimates for leasable resources in each planning area, estimates were prepared showing the distribution of these undiscovered resources in each area by dollar categories of the net economic value. Table 4 shows the leasable oil and gas resources in each of three net economic value categories: $0.00 to $3.00; $3.00 to $6.00; $6.00 to $10.00 per barrel for the low and high starting price cases.

FIGURE 1

OIL PRICE SCENARIOS FOR THE 5-YEAR OCS LEASING PROGRAM



The variation in oil prices used to estimate leasable resources and net social value for the 5-Year OCS Leasing Program is depicted by the bold lines. The $19 and $29 starting prices reflect a range of weighted average FOB prices of U.S. imports of oil at the time when the analysis began in 1984. These prices are then adjusted for real price growth and inflation (nominal price growth) to arrive at January 1987 starting prices of oil for the 5-Year Program. Thereafter, prices are adjusted assuming a 1% annual real price growth. The broken lines reflect a wider range of real price growth assumptions for sensitivity analysis.

Table 3

Variation in Estimated Net Economic Value
of Unleased Undiscovered Oil and Gas Resources /1
in Leasable Prospects as of January 1987 /2
(from $19 to $29 per barrel 1984 starting prices)

Planning Area /3	Estimated Net Economic Value (Millions of 1987 Dollars) Starting Prices @ $19/bbl	@ $29/bbl
Central Gulf of Mexico	17,860	35,245
Western Gulf of Mexico	14,506	31,299
Southern California	3,975	9,088
South Atlantic	839	3,022
Central California	765	2,649
Northern California	910	2,463
Eastern Gulf of Mexico	675	2,379
Navarin Basin	121	2,591
Mid-Atlantic	198	723
Washington-Oregon	207	454
Beaufort Sea /4	*	678
St. George Basin	*	464
North Atlantic	85	258
Straits of Florida	14	33
Chukchi Sea /4	*	596
Gulf of Alaska	*	33
North Aleutian Basin	*	20
Norton Basin	*	20
Kodiak	*	*
Hope Basin	*	*
Shumagin	*	*
Cook Inlet	*	*

* Negligible (estimated to be less than 0.5 million of $1987, using base case assumptions).

/1 Net economic value is the revenue obtained by the sale of oil and gas less the exploration, development, production, and transportation costs necessary to bring the oil and gas to market. Net economic value for upcoming sales scheduled to be held before the start of this 5-year program is not included in these estimates.

/2 See footnote 2, Table 2, for price and discount rate assumptions.

/3 The planning areas are ordered by net economic value at $24/bbl.

/4 Net economic value calculations exclude Beaufort Sea and Chukchi Sea natural gas (see Appendix F).

Table 4

Distribution of Risked Developable Resources by Net Economic Value Category Showing Variation by Starting Oil Prices /1
(Millions of barrels of oil equivalent (BOE))

	Leasable Resources /3							
	Net Economic Value ($1987 per barrel)						Developable but/4 not Leasable	
	$6.00 to $10.00		$3.00 to $6.00		Below $3.00			
Planning Area /2	@$19/bbl	@$29/bbl	@$19/bbl	@$29/bbl	@19/bbl	@$29/bbl	@19/bbl	@29/bbl
Central Gulf of Mexico	*	4,539	4,300	123	303	*	577	518
Western Gulf of Mexico	*	4,087	2,644	543	1,847	*	139	*
Southern California	*	790	617	474	429	*	554	336
South Atlantic	*	*	*	462	392	268	498	160
Central California	*	129	92	276	228	*	140	55
Northern California	*	186	151	228	130	*	169	36
Eastern Gulf of Mexico	*	211	31	206	300	54	249	109
Navarin Basin	*	*	*	516	178	269	912	305
Mid-Atlantic	*	*	*	88	88	96	712	616
Washington-Oregon	*	46	46	10	*	*	104	94
Beaufort Sea /5	*	*	*	*	*	308	460	152
St. George Basin	*	*	*	*	*	160	380	220
North Atlantic	*	13	13	22	22	28	315	276
Straits of Florida	*	*	*	6	6	*	14	14
Chukchi Sea /5	*	*	*	*	*	400	540	140
Gulf of Alaska	*	*	*	*	*	28	150	122
North Aleutian Basin	*	*	*	*	*	16	90	74
Norton Basin	*	*	*	*	*	12	40	28
Kodiak	*	*	*	*	*	*	30	30
Hope Basin	*	*	*	*	*	*	10	10
Shumagin	*	*	*	*	*	*	10	10
Cook Inlet	*	*	*	*	*	*	10	10

* Negligible (estimated to be less than 0.5 million BOE).

/1 Note that where leasable resource estimates appear to decline at higher prices, the resources have actually been reclassified into higher net economic value categories.

/2 The planning areas are ordered by net economic value at $24/bbl.

/3 See footnote 2 to Table 2. The data in Table 4 are taken from Table 7 in Appendix F.

/4 Developable resources are those that are profitable for a lessee to produce, given that they have already been discovered.

/5 Calculations exclude Beaufort Sea and Chukchi Sea natural gas (see Appendix F).

These disaggregated estimates of resources allow more detailed consideration of the economic characteristics of the oil and gas resources within each area. For example, the Western and Central Gulf of Mexico areas have substantial resource potential in the highest net economic value categories as well as a small amount in the lower value category. This means that there will be a substantial number of good investment opportunities to be found there even with a significant drop in the price of oil. (Table 8 in Appendix F substantiates this). The distribution of the resources in the low value category in planning areas such as the Navarin Basin, St. George, and Beaufort Sea make these areas highly susceptible to a drop in oil prices.

The three California areas, the Eastern Gulf of Mexico, and Washington-Oregon, also have significant resource potential in the highest value categories. The estimates of resource potential in the upper value categories means that leasing and investment in exploration will be worthwhile even at prices as low as the $19 per barrel case price. (See Table 8 of Appendix F.)

Estimates were also made of the effect of delaying leasing and the investments leading to production in each area. As explained in Appendix F, if oil prices are expected to increase at a constant annual rate, highest cost, lowest valued prospects are expected to increase in net economic value enough to yield benefits from delays while the lowest cost, highest valued prospects are expected to decrease in net economic value if investments are delayed. Estimates of the simple average annual dollar changes in net economic value per barrel were calculated assuming that real oil prices increase at 1 percent and 2 percent per year.

Table 6 of the SID displays the results of applying the per barrel delay costs for the $19 and $29 per barrel price cases to the leasable resources estimated for each planning area. The results yield estimates of the average annual costs of delaying leasing for all leasable resources in each planning area. For all cases, in virtually all planning areas (except for the Navarin Basin in the low price case), a delay in leasing would be expected to result in an overall decline in net economic value for the planning area. Comparing the results in Table 6 with those in Table 4 demonstrates that areas with more low cost, high valued resource prospects such as the Gulf of Mexico and Pacific areas tend to have higher costs of delay. Areas with predominantly lower valued resource prospects have lower delay costs.

To test the sensitivity of the delay analyses to a change in the discount rate assumption, a lower rate--6 percent--was also examined. The results are displayed in Table 9 of Appendix F.

In assessing the results of the analysis, it should be noted that there is a high degree of uncertainty surrounding resource estimates, costs, technology, economic parameters, and therefore each area's net economic

Table 5

Sensitivity of Net Economic Value (NEV) to the Starting Oil Price/1

Planning Area	Net Economic Value ($/BOE) Starting Price @19/bbl	Starting Price @$29/bbl
Central Gulf of Mexico	3.88	7.56
Western Gulf of Mexico	3.23	6.76
Southern California	3.80	7.19
South Atlantic	2.14	4.14
Central California	2.39	6.54
Northern California	3.24	5.95
Eastern Gulf of Mexico	2.04	5.05
Navarin Basin	0.68	3.30
Mid-Atlantic	2.25	3.93
Washington-Oregon	4.50	8.11
Beaufort Sea	0	2.20
St. George Basin	0	2.90
North Atlantic	2.43	3.49
Straits of Florida	2.27	5.49
Chukchi Sea	0	1.49
Gulf of Alaska	0	1.19
North Aleutian Basin	0	1.28
Norton Basin	0	1.66
Kodiak	0	0
Hope Basin	0	0
Shumagin	0	0
Cook Inlet	0	0

/1 Data taken from Appendix F, Table 8.

Assumptions: Annual Oil Price Change: 1 percent
Discount Rate: 8 percent

Table 6

Simple Average Annual Change in Net Economic Value for Leasable Resources from a One-Year Delay in Leasing, Showing Variation by Starting Oil Price /1

Planning Area	Net Economic Value (Millions of 1987 Dollars) Starting Price @ $19/bbl	Starting Price @ $29/bbl
Central Gulf of Mexico	-1,013	-2,145
Western Gulf of Mexico	-764	-1,852
Southern California	-220	-493
South Atlantic	-39	-153
Central California	-29	-142
Northern California	-48	-133
Eastern Gulf of Mexico	-26	-136
Navarin Basin	+2	-86
Mid-Atlantic	-9	-35
Washington-Oregon	-12	-22
Beaufort Sea	*	-31
St. George Basin	*	-19
North Atlantic	-4	-12
Straits of Florida	-1	-2
Chukchi Sea	*	-36
Gulf of Alaska	*	-1
North Aleutian Basin	*	*
Norton Basin	*	*
Kodiak	*	*
Hope Basin	*	*
Shumagin	*	*
Cook Inlet	*	*

* Negligible (estimated to be less than .5 million of $1987, using base case assumptions).

/1 Data from Appendix F, Table 9.

Assumptions: Annual Oil Price Change: 1 percent
Discount Rate: 8 percent

value. These estimates reflect a detailed, thorough, quantitative analysis by MMS professionals, but the estimates are subject to significant limitations (see Appendix F and Appendix S). Prudent use of these estimates would be limited to drawing general distinctions among planning areas which have estimates which differ by an order of magnitude or more. The estimates should be viewed as relative approximations rather than absolute numbers.

II.B.2 Estimated Social Costs

Background

In compliance with California v. Watt (I) and (II), a quantitative analysis was made of some of the potential social costs which might be associated with development of the recoverable hydrocarbon resources in each of the OCS planning areas. While the estimated social costs are associated with the development of the resources of each of the planning areas, they should be viewed as costs to the Nation as a whole. This is so since not all of the costs resulting from development of the resources in a planning area are necessarily borne by the residents living near the area.

Focusing on costs to the Nation as a whole is also necessary to provide the comparability among areas necessary to the performance of the required cost-benefit analysis since the net economic value estimates measure benefits to the Nation as a whole. Also, in order to make costs and benefits comparable, the social cost analysis is keyed to the leasable resource estimates used in the net economic value analysis (see Table 2). Leasable resources are calculated on a "risked" basis--i.e., incorporating an estimate of the probability of occurrence of potential effects as well as their magnitude. The EIS, on the other hand, will be based on "conditional" resource estimates, which are usually larger because they are not modified by a risk factor. Nonetheless, this social cost analysis errs on the side of overstating costs in a number of ways.

A vitally important reason that the estimates of social costs are likely overstated is that development of the United States' OCS oil and gas resources is conducted in an increasingly safe and environmentally sound manner. The program has an excellent record of few personnel and mechanical failures which have resulted in environmental damage or adverse coastal zone impacts (see Appendix Q). While the calculations are based on historical data, advances in technology have lowered and can be expected to continue to lower the chance of such damage and impacts. However, if there were an increase in activities in areas with harsh operating conditions, that trend might be affected adversely. The substantial OCS oil and gas environmental studies program of the Department of the Interior (DOI) is continuing to shed light on where and how damages may occur and how they can be prevented. The regulatory and operating procedures of the DOI have mitigated and will continue to mitigate many of the potential damages.

Furthermore, the OCS Lands Act provides a means to compensate those who are adversely affected in the event that OCS oil spill-related damage or commercial fishing gear losses occur. While not taken into account in the computation of social costs, those compensation payments have been used to compute the distribution of costs discussed in Part II.C.

A full description of all the potential costs estimated for this analysis is presented in Appendix G. The introduction and summary to Appendix G also provides a more detailed explanation of the analytical approach, the meaning of social costs, the method of calculation, the data sources used, and the reliability of estimates.

Social Costs

Social costs include the costs of responding to and cleaning up oil spills, commercial fishing loses, recreation, air quality, and wetland losses, infrastructure costs, research and legal costs, and other market and non-market

valued environmental and socioeconomic costs which are not normally included in the costs of operations involved in OCS oil and gas exploration, development, production, and transportation.

In this analysis, social cost estimates are related to potential large oil spills (1,000 barrels or more), small spills (under 1,000 barrels), spill control and cleanup costs, commercial fishing losses, recreation losses, potential ecological damages, real property losses, legal expenses, subsistence losses, the value of oil spilled, research expenses, and other costs. Estimates were also made for the following potential non-oil spill costs: potential air quality losses; onshore wetlands losses; losses resulting from physical conflicts between commercial fishing and OCS oil and gas operations; and infrastructure costs.

Since social costs are costs to the Nation as a whole, they are measured net of the social costs avoided because OCS oil reduces the quantity of oil imported and hence reduces spills of imported oil. Thus, Appendix G first calculates gross social costs and then subtracts from that figure the costs avoided because oil imports are reduced in order to calculate the net social costs displayed in Table 7.

Of the potential OCS oil and gas damages that could occur, the analysis was restricted to those for which cost data (in dollars) exist and, in the professional judgment of the staff of the MMS could be adapted to the analysis. Additional information about these potential damages as well as information about other potential quantifiable damages and unquantifiable damages which were not included in this analysis will be described in the EIS and elsewhere in the SID. These descriptions, along with this social cost analysis, will allow consideration of variations in potential environmental damage and adverse coastal zone impacts from planning area to planning area in selecting the timing and location of leasing.

Comparison of the New Analysis and the 1982 Analysis

The analysis of social costs updates, refines, and extends a similar analysis undertaken in formulating the 1982 5-Year Proposed OCS Leasing Program. The current analysis reflects three major differences: (1) updated and considerably lower estimates of unleased oil and natural gas resources; (2) substantially lower tanker oil spillage rates; and (3) refinements in the analysis. The net effect of these changes is to increase the new estimated potential social costs of developing oil and gas resources in the Central and Western Gulf of Mexico and to decrease the estimated costs of developing hydrocarbon resources in other areas.

Appendix G demonstrates a number of fundamental differences between the total and per-barrel social costs estimated in connection with the 1982 proposed 5-year leasing program and the social costs estimated for consideration in the formulation of the new program. Estimated oil spill and non-spill costs per unit of production in general are considerably less in this analysis than those estimated in 1982. Mitigating measures to avoid wetland and air quality losses, lower oil spillage rates because of improved tanker and pipeline safety records, as well

as lower resource estimates and the use of refined economic concepts explain the lower costs in this analysis as compared to the 1982 results. The major differences between this analysis and the 1982 analysis are explained in section H of Appendix G.

The Social Cost Analysis

Estimates of the potential costs in each category of damage were based on data and judgments derived from the results of a literature search, the analysis of relative environmental sensitivity and relative marine productivity (see Part II.B.3 and Appendix I), knowledge of the value of other uses of the sea, the estimated amount of oil and gas production, the chance of spills reaching shore, the likelihood of resulting damage in each area, information received in response to requests for comments (summarized in Appendix B), and a number of other factors.

The potential social cost estimates are summarized in Table 7. Table 7 shows that the estimates associated with the development of the leasable resources in each planning area range from a total estimated social cost of $32.5 million for the Central Gulf of Mexico to a total social cost of less than $0.5 million for several Alaskan OCS areas, the Straits of Florida, and Washington-Oregon.

Estimated potential social costs vary considerably depending on the planning area. For instance, recreation losses caused by oil spills are estimated to be relatively low in the Alaskan areas but higher elsewhere. Based on an analysis of commercial fishing landings statistics published by the National Marine Fisheries Service and the State of Alaska, commercial fishing losses per barrel of oil spilled are estimated to be high in the North Atlantic and Central Gulf of Mexico and moderate to low for other areas. Also, it is estimated that per-barrel subsistence losses may be significant in some areas of Alaska, but they are projected to be negligible outside Alaska. The estimated unit cost of oil spill control and cleanup is considerably higher for Alaskan areas vs. the "lower 48" (see Appendix G).

Losses per billion barrels of oil equivalent (BBOE) due to air pollution were judged to be negligible in all the Alaskan areas except Cook Inlet, where they were estimated to be low. Air pollution losses in areas of the contiguous 48 States are negligible except for the Southern California area and the Central Gulf of Mexico area, where they are estimated to be low, due in large part to the concentrated coastal population and the topographical features and climate of these areas. (see Appendix G).

Generally speaking, there is a direct relationship between a planning area's total potential social cost and the total hydrocarbon resources estimated to be produced in the area. However, the oil-gas resource composition, the probability of a spill reaching shore, the value of each area's marine resources, and socioeconomic characteristics influence estimated social costs. The relative marine productivity/environmental sensitivity analysis is also an input to the estimation of potential social costs as well as a separate consideration in itself.

Table 7

Range of Estimated Potential Net Discounted Total Social Costs
Associated with Total Production of the Leasable Resources
Estimated to be in Each Planning Area
(In Millions of $ 1987) /1

Central Gulf of Mexico	$40.46 - 40.52
Western Gulf of Mexico	28.86 - 29.44
Southern California	16.97 - 20.10
Navarin Basin	6.58 - 26.97
Northern California	4.80 - 6.36
Central California	5.10 - 6.24
Eastern Gulf of Mexico	4.89 - 6.48
South Atlantic	2.78 - 4.61
St. George Basin	0.00 - 2.90
Beaufort Sea	* - 6.24
Mid-Atlantic	0.89 - 1.51
North Atlantic	0.78 - 0.98
Washington-Oregon	* - 0.54
Straits of Florida	* - *
Chukchi Sea	* - 5.28
North Aleutian basin	* - *
Gulf of Alaska	* - *
Norton Basin	* - *
Kodiak	* - *
Hope Basin	* - *
Shumagin	* - *
Cook Inlet	* - *

/1 Net Present Value, calculated with a discount rate of 8 percent (see Appendix G). The low numbers in the range correspond to resource estimates based on a $19 per barrel starting oil price and the high numbers correspond to a $29 per barrel starting oil price. The planning areas are ordered for total social cost values 0$24 per barrel.

* Estimated to be less than $0.5 million.

The net effect of the factors influencing potential social costs is indicated in Table 8 by the social costs per unit of production--here measured as the social costs per billion barrels of oil equivalent (BBOE). The rankings of the areas in terms of costs per BBOE differ from their total cost rankings. In several cases, areas with relatively low estimated recoverable resources have relatively high social costs per BBOE reflecting a combination of factors (environmental sensitivity and productivity, high valued commercial fisheries, recreation losses and cleanup costs, particularly for areas where there is a high chance that any spills which occur will come ashore).

Potential wetland losses from onshore development related to OCS production, although considerably lower than similar estimates made in 1982, are estimated to be highest for the Central /1 and Western Gulf of Mexico and Southern California areas. The key determinants of these estimates are the additional activity estimated to take place in each area, the extent to which existing facilities can accommodate the additional activity, and the effectiveness of governmental permitting requirements in mitigating these potential losses (see Appendix Q).

While social costs measure the estimated potential cost of producing the area's unleased leasable resources to the Nation as a whole, the estimate does not indicate the distribution of costs among the population. The distribution of such costs is treated in Part II.C, in the discussion of the equitable sharing of developmental benefits and environmental risks.

Because of the uncertainty and difficulties associated with estimating several categories of cost, a sensitivity analysis was carried out to determine the magnitude of an area's social cost that would be estimated if specific unit costs are presumed to be even higher than the overstated costs used to develop the estimates of social costs presented in Table 7. The results of the sensitivity analysis in Appendix G indicate that while the costs in each planning area are greater than the results presented in Table 7, the ranking of OCS areas by their net social value (see Part II.D of this SID) does not change. This is because: (1) only a subset of all costs (i.e., the largest and most uncertain costs) is assumed to increase; and (2) when individual oil spill costs increase, the social cost savings from backing out imported oil also increase, thereby moderating the net increase in social costs.

Nonetheless, in assessing the results of the analysis, it is important to keep in mind the high degree of uncertainty associated with the estimates. Given the uncertainty of the data on which the analysis was based, and the necessity of heavy reliance on judgment, the social cost estimates should be considered, at best, as an order of magnitude approximation. As such, prudent use of these estimates would make distinctions between differences from area to area only if they are substantially more than an order of magnitude in size (that is, if one estimate is substantially more than 10 times the other).

/1 The loss of coastal wetlands has been most pronounced in the Central Gulf of Mexico. Current information on the processes causing wetland loss implicates large-scale geologic and oceanographic processes along the Louisiana coast. In comparison to these other forces, OCS-related activities do not appear to have been a significant contributor to the loss of coastal wetlands in this area. (See Appendix G).

Table 8

Estimated Potential Social Costs Per Billion Barrels of Oil Equivalent (BBOE) Associated With Total Production of Leasable Resources Estimated to be in Each Planning Area (In Millions of $ 1987) /1

Area	Net Costs Per BBOE
Straits of Florida	$53
Navarin Basin	34
Cook Inlet	28
Norton Basin	22
North Atlantic	22
Beaufort Sea	21
St. George Basin	18
North Aleutian Basin	18
Southern California	16
Central California	15
Northern California	15
Kodiak	15
Gulf of Alaska	14
Eastern Gulf of Mexico	14
Chukchi Sea	13
Washington-Oregon	10
Shumagin	9
Central Gulf of Mexico	9
Mid-Atlantic	8
Hope Basin	8
Western Gulf of Mexico	6
South Atlantic	6

/1 Net Present Value, calculated with a discount rate of 8 percent assuming a starting oil price of $29 per barrel. The $29 per barrel estimates are presented because nine planning areas have no leaseable resources at $19 per barrel. The variation of the BBOE social costs for most planning areas is quite constant across the $19 per barrel to $29 per barrel resource estimates. The BBOE net social cost estimates for the Cook Inlet, Hope Basin, Kodiak, and Shumagin planning areas were calculated using estimates of developable resources with a $29 per barrel oil price (see Appendix G).

The Straits of Florida has the highest net social costs per BBOE across all planning areas even though its total social costs are among the lowest (less than $0.5 million). The very high costs per BBOE result from dividing the estimated total net social costs for the Straits of Florida by the estimated leasable resources and then expressing the costs on a per BBOE basis (see Appendix G). The estimated social costs for the Straits of Florida are nearly all fixed costs (wetland loss due to pipeline installation), which would not increase proportionately if the resource estimate increased. Thus, the BBOE cost for the Straits of Florida would be lower if the resource estimate were higher. [Footnote continued on the next page.]

(Footnote /1 continued).

The problem of high fixed costs distorting the BBOE estimates of net costs does not fully explain the high BBOE costs for the Navarin Basin. The high net social costs per BBOE for the Navarin Basin are caused by a combination of factors the most important of which are the transportation scenario for the Navarin Basin and the relatively high oil to gas ratio for the Navarin Basin.

Oil produced from the Navarin Basin will be transported by pipelines to either onshore or offshore tanker loading facilities. Ice breaking tankers will be used to transport Navarin Basin oil to a port on the south side of the Alaska peninsula where it will be off-loaded and loaded onto tankers for shipment to market. Thus, Navarin Basin oil has three transportation legs with their attendant risks of oil spills while all other planning areas outside of the Bering Sea have only one or two transportation legs. This extra tanker transportation segment for the Navarin Basin increases its estimated oil spillage per billion barrels by more than 50 percent over planning areas that use both pipelines and tankers, i.e., all Atlantic planning areas and all other Alaskan planning areas. By comparison to planning areas that use pipeline or tankers, but not both, Central and Western Gulf of Mexico and Southern California, the additional oil spillage for the Navarin Basin is even larger. The estimated amount of oil spilled per billion barrels for the Navarin Basin is over 213 percent larger than the estimated amount of oil spilled per billion barrels for the Central Gulf of Mexico.

The ratio of oil to gas in a planning area's resources can also affect the net social costs per BBOE. The Navarin Basin is estimated to have about 82 percent oil in its BBOE while other planning areas have lower percentages oil in their BBOE. For example, the Central Gulf of Mexico has approximately 40 percent oil in its BBOE while the Western Gulf of Mexico has less than 30 percent oil in its BBOE. Production of gas increases the BBOE for a planning area but does not increase the estimated amount of oil spilled, and most of the social costs are related to spilled oil. Thus, planning areas with a high percentage of oil in their BBOE, like the Navarin Basin, tend to have higher per-BBOE social costs.

II.B.3. Relative Marine Productivity and Environmental Sensitivity

Section 18(a)(2)(G) of the OCS Lands Act, as amended, requires that the Secretary of the Interior consider the relative marine productivity and environmental sensitivity of the various oil and gas bearing physiographic regions of the OCS in determining the timing and location of oil and gas activities. Analyses of relative marine productivity and environmental sensitivity were conducted to aid in the development of the 1982 OCS leasing schedule (Part II.B and Appendix 10 of the SID for the 1982 program). Those analyses demonstrated the complexity of collecting, analyzing, and interpreting scientific information to satisfy the requirements of section 18(a)(2)(G). In spite of the difficulties described in the 1982 analyses, the approaches to those analyses were upheld as reasonable by the U.S. Court of Appeals for the District of Columbia on July 5, 1983.

In preparation for current analyses, analytical approaches were discussed with the OCS Advisory Board Policy Committee (October 1984) and Scientific Committee (November 1984). The present analysis incorporates some of the advice and guidance received. Some of the suggestions from these advisory groups were more appropriate to environmental analyses which will follow the present analyses. These suggestions will be considered during the preparation of the environmental impact statement (EIS) for the proposed program and in subsequent sale-specific EIS's. Almost all parties who provided advice agreed that both the productivity and sensitivity analyses required by section 18(a)(2)(G) are complex and difficult. In addition to this advice, the Department has received or developed more information on the habitats and biota of the OCS than was available in 1982. The principal mechanism for the Department to develop such information is the OCS Environmental Studies Program administered by the Minerals Management Service.

Appendix I contains a more detailed explanation of the relative marine productivity and environmental sensitivity analyses summarized here. The information developed in the present analyses will be considered in and of itself as well as an input to the social costs analysis in Part II.B.2 and Appendix G of this SID. The assumptions used to determine the environmental sensitivity of a habitat or resource differ from those used in the analysis of social costs in the following ways:

1. The probability of the occurrence of an oil spill is an integral part of the calculation of social costs. This probability is a function of the estimate of oil and gas resources in the planning areas. The sensitivity analysis is based upon the assumption that an oil spill has occurred and that the spilled oil has contacted habitats or biota of the planning area. The sensitivity analysis does not rely upon resource estimates or consider the probability of the occurrence of an oil spill.

2. The calculation of social costs includes potential costs from air pollutant emissions and the loss of coastal wetlands. These impacts are not included in the sensitivity analysis.

3. The analysis of social costs includes losses of commercial and/or subsistence fish resources. The present analysis includes evaluations of the sensitivity of juvenile and adult fish and shellfish to crude oil. The social use of these resources is not considered in the sensitivity analysis.

Relative Marine Productivity

The term "productivity" has a distinct meaning to marine biologists. It means the "primary productivity" of marine plants. Primary productivity is the amount of plant tissue produced through photosynthetic fixation of carbon during a standard period of time. Both phytoplankton, microscopic marine plants, and fixed or rooted plants contribute to the primary productivity of most OCS planning areas. However, phytoplankton are the most important primary producers because of their large numbers and their wide distribution. Rooted or fixed plants are generally confined to the shallow portions of the planning areas. Phytoplankton can occupy all surface waters of a planning area and can fix carbon as long as sufficient light and nutrients are available. Riley (1970) estimated the normal range of marine primary productivity to be between 50 and 150 grams of carbon per square meter of ocean surface per year. Productivity in inshore areas and areas of upwelling can be as much as ten times greater than oceanic productivity.

The primary productivity of phytoplankton was used to rank the various planning areas in the 1982 analysis of relative marine productivity. Measurements of phytoplankton productivity have been made in almost all of the planning areas. The methods for measuring phytoplankton productivity are relatively standard. Most of the data used in the present analysis, except that provided by Smith and Kalber (1974), is based on ^{14}C assimilation measurements of phytoplankton productivity. Results of phytoplankton productivity studies are expressed in terms of the amount of carbon fixed during photosynthesis per unit area in a specified time. The figures used in the present analysis are expressed as grams of carbon fixed per square meter per year ($gC/m^2/yr$). By using a period of one year for reporting primary productivity, periods of extremely high or low productivity are incorporated in their appropriate importance in terms of their contribution to the annual productivity. This is especially important in areas where productivity is highly seasonal.

Phytoplankton productivity can vary more significantly within a planning area than between planning areas. For example, O'Reilley and Busch (1984) reported that productivity in the shallow areas of Georges Bank (North Atlantic) averaged 470 $gC/m^2/yr$ while in deeper waters landward of the shelf break, productivity averaged 370 $gC/m^2/yr$. Productivity in the deeper waters of the North Atlantic averaged 230 $gC/m^2/yr$. Determining an appropriate range or average productivity rate for the North Atlantic or any other planning area requires careful attention to the temporal and spatial significance of reported observations.

The 1982 analysis of marine productivity relied upon the "Estimation of organic production in the oceans" (Figure 1.1-5) presented by Smith and Kalber (1974). The productivity ranges provided in that undocumented map

were used to rank the OCS planning areas. In the present analysis, the estimates of Smith and Kalber (1974) were compared with more current estimates based upon documented measurements (Table 9.1). In the 1982 analysis, the planning areas were grouped into four productivity classes: highest, next-to-highest, next-to-lowest, and lowest. The North Aleutian Basin and the St. George Basin were the only planning areas in the "highest" class. Based upon the data of Goering and McRoy (1981), the average annual productivity of these planning areas is substantially lower than the values reported by Smith and Kalber (1974). Only three productivity classes (high, moderate, and low) were distinguished in the present analysis (Table 9.2).

Twelve planning areas are included in the "high productivity" class. Further differentiation within this group must await more precise definition of the appropriate ranges or other statistical descriptions. The principal difference between the present analysis and the 1982 analysis is the elimination of the "highest" productivity class from the 1982 analysis and the inclusion of the North Aleutian Basin and the St. George Basin in the "high" productivity class of the present analysis.

In the present analysis, the planning areas designated as having "moderate" productivity are those with reported observations ranging from 50 to 200 $gC/m^2/yr$. Seven planning areas occur in this class. Although some high observations are reported for some of these areas, the overall annual productivity of these areas appears to be in the "moderate" range.

Finally, the three planning areas in the Arctic (Hope Basin, Chukchi Sea, and Beaufort Sea) are the least productive of the OCS planning areas. Information from Carey (1978) and Schell and Horner (1981) confirms the low productivity of these areas.

Additional Measures of Marine Productivity

The phytoplankton productivity data discussed in the present analysis is some of the most consistently expressed data in biological oceanography. Even so, comparisons among observed productivities are tenuous for the reasons described in the preceding discussion. The problems associated with attempting to use other biota to assess marine productivity are illustrated in Table 6 of the 1982 analysis. Even with the additional data collected since 1982, available information is not sufficient to support a rigorous evaluation of the relative abundance of various organisms in the OCS planning areas. In many instances, quantitative information on some biota is unavailable, while for others, the development of "planning-area representative" information is not practical.

However, information on the relative abundance of eight additional categories of biota was compiled, reviewed, and used in the matrix exemplified in Table 9.3 to complete the environmental sensitivity analysis. Available information on standing stocks and distributions was used to determine whether the "abundance" of the biota in a planning area relative to all other planning areas was high, moderate, or low. Making such determinations generally required extrapolations of existing data and simplifying assumptions. Some of these extrapolations and assumptions are described in the following sections.

TABLE 9.1

Marine Phytoplankton Productivity by Planning Area
Expressed as Grams of Carbon Fixed per Square Meter per Year

Planning Area	Range of Values Used in the 1982 Analysis ($gC/m^2/yr$)*	More Recent Observations ($gC/m^2/yr$)	Reference
North Atlantic	200-400	230-470	O'Reilly & Busch (1984)
Mid-Atlantic	200-400	260-370	O'Reilly & Busch (1984)
South Atlantic	50-200	130-360	Haines & Dunstan (1975) Yoder et al. (1983)
Straits of Florida	50-100		
Eastern Gulf of Mexico	50-100	10-110	UMES (1985)
Central Gulf of Mexico	50-100	10-220	El-Sayed & Turner (1977)
Western Gulf of Mexico	50-100	15-70	El-Sayed & Turner (1977)
Southern California	200-400	180-360	Eppley et al. (1979)
Central California	200-400	10-470	Riznyk (1977)
Northern California	200-400	10-470	Riznyk (1977)
Washington/Oregon	------	35-350	Small et al. (1972)
Gulf of Alaska	200-400		
Cook Inlet	200-400		Griffiths et al. (1982)
Kodiak	200-400		
Shumagin	200-400		
North Aleutian Basin	400-7300	120-400	Goering & McRoy (1981)
St. George Basin	400-7300		
Navarin Basin	50-200		
Norton Basin	50-100		
Hope Basin	<50		
Chukchi Sea	<50	18-28	Carey (1978)
Beaufort Sea	<50	10-20	Schell & Horner (1981)

* Data from Smith and Kalber(1974)

TABLE 9.2

Relative Phytoplankton Productivity of the OCS Planning Areas Expressed as Grams of Carbon Fixed per Square Meter per Year

High Productivity (200 to 500 $gC/m^2/yr$)

North Atlantic
Mid-Atlantic
North Aleutian Basin
St. George Basin
Southern California
Central California
Northern California
Washington and Oregon
Gulf of Alaska
Cook Inlet
Kodiak
Shumagin

Moderate Productivity (50 to 200 $gC/m^2/yr$)

South Atlantic
Straits of Florida
Eastern Gulf of Mexico
Central Gulf of Mexico
Western Gulf of Mexico
Navarin Basin
Norton Basin

Low Productivity (<50 $gC/m^2/yr$)

Hope Basin
Chukchi Sea
Beaufort Sea

Relative Environmental Sensitivity

The concept of environmental sensitivity is even more complex than the concept of marine productivity. The 1982 analysis clearly demonstrated this complexity.

The 1982 analysis of environmental sensitivity was based, in large part, on an evaluation of the sensitivity of various coastal and marine habitats and biota to spilled crude oil. Limiting the analysis to spilled crude oil provided the following advantages:

1. Different areas of the OCS could be evaluated against a common factor, in this case, spilled crude oil.
2. Effects from overlapping factors could be avoided.
3. Oil spills, although rare, would cause the largest, most visible, and measurable effects of OCS activities.

The present analysis of environmental sensitivity also concentrates on the effects of spilled oil. However, some other factors were also evaluated in Appendix I-2 of the draft proposed program. These evaluations are not repeated in the proposed program but are available for review. These factors include the following:

1. Operational discharges from OCS activities (drilling muds, cuttings, and formation waters).
2. Noise generated by OCS activities.
3. Habitat alteration from the installation of OCS facilities.
4. Air emissions from OCS operations.

These factors are not included in the calculations because of the difficulty of measuring their effects on the same basis that the effects of oil spills. In addition, information on the effects of these factors on habitats and biota throughout the entire OCS is not available. The effects of operational discharges, noise, habitat alteration, and air emissions will be considered in other environmental analyses prepared for the 5-Year Program, such as the EIS on the proposed program, and in subsequent sale-specific EIS's. While the cumulative effects of these four factors may be more extensive and long lasting than the effects of a large oil spill, the Department of the Interior and other Federal, State, and local agencies have means available to control some of the adverse effects of these factors.

For the present analysis, environmental sensitivity is defined in terms of the following variables:

1. the severity of damage resulting from the contact of spilled oil with various coastal and marine habitats and biota (this was designated as the persistence of oil in the 1982 analysis), and

2. the time required for the habitat or population to recover from the effects of contact with spilled oil.

The following assumptions are also included in the present environmental sensitivity analysis:

1. Spilled oil has not weathered significantly when it contacts the habitat or population. This assumption is conservative and provides an assessment of the most severe effects of spilled oil by eliminating the mitigating effects of weathering in the analysis. It also eliminates consideration of the distance between sensitive resources and potential oil fields or transportation routes and the mitigating effects of weathering on spilled oil moving from the site of production or transportation to the sensitive resource.

2. All of the biological populations in a planning area are contacted by spilled oil. Migratory species, which may inhabit the planning area for only a short period, are assumed to be present and contacted by spilled oil. Resources with seasonal sensitivities are assumed to be in their most sensitive stage when they are contacted by oil.

Performing an accurate analysis of environmental sensitivity requires a substantial amount of information on the spatial and temporal distribution of resources and the variations in their sensitivities to spilled oil. This is especially true where seasonal phenomena such as changes in productivity or the presence of migratory species would significantly increase or decrease the overall sensitivity of a planning area. If sufficient data were avialable, the overall environmental sensitivity of a planning area would be the sum of the sensitivities of its components integrated over time. This concept was reviewed during the preparation of the present analysis. It was abandoned because the minimum necessary information to conduct such an analysis is not available. Some information on some resources in some planning areas is avaiable, but the data are neither consistent nor available for all planning areas. As a result, the present analysis contains the simplifying assumptions described above. If adequate information were available, it would be possible to develop both expected and worst-case sensitivities. The reliance of the present analysis on conservative assumptions is, nonetheless, appropriate for the purpose of comparing the relative environmental sensitivities of the OCS planning areas.

Relative Marine Productivity/Environmental Sensitivity

In the present analysis, the distributions and environmental sensitivities of the three ecological components within and/or on the adjacent coast of each OCS planning area are evaluated. These three components are coastal habitats, marine habitats, and biota. Table 9.3 is an example of the calculations performed for each of these components. The calculations for each planning area are included in Appendix I-1.

The relative marine productivity and environmental sensitivity of the OCS planning areas are shown in Table 9.4. Alaskan OCS planning areas occupy the extremes of this table. The Navarin Basin has the lowest score because it has no coastal habitats. The planning areas with the highest scores are Hope Basin, North Aleutian Basin, St. George Basin, and Norton Basin. Since much of the information used in the calculation of relative marine productivity and environmental sensitivity is qualitative, each assigned value in the calculation has some degree of uncertainty. Thus, the scores provided in Table 9.4 should be viewed as estimates surrounded by some undefined variance. Scores with small differences between them should be viewed as relatively equal.

TABLE 9.3

Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: Hypothetical

Overall Total Score: 290

	Distribution of Resource (1)	(2)	Sensitivity Coefficient (3)	(4)	Score (5)
Coastal Habitats	Miles				
Estuaries/Wetlands	200	33	High	225	74.25
Sandy Beaches	300	50	Low	45	22.50
Rocky Beaches	100	17	Moderate	135	22.95
TOTAL	600				119.70
Marine Habitats	Acres				
Submerged Vegetation	1,200,000	5.3	Moderate	135	7.16
Submarine Canyons	None	0.0	Low	45	0.00
Coral Reefs	5,000	0.02	High	225	0.05
Hard Bottoms	600,000	2.6	Low	45	1.17
Shelf Break Zone	850,000	3.7	Low	45	1.67
Mud/Sand Bottom	20,000,000	88.2	Low	45	39.69
TOTAL	22,655,000				49.74
Biota					
Phytoplankton	High	5	Low	1	5
Juvenile Fish/Shellfish	High	5	High	5	25
Adult Fish/Shellfish	Moderate	3	Moderate	3	15
Mud/Sand Benthos	Low	1	Low	1	1
Coastal Birds	Moderate	3	High	5	15
Marine Birds	High	5	High	5	25
Marine Turtles	None	0	Low	1	0
Marine Mammals	High	5	High	5	25
Whales	Moderate	3	High	5	15
TOTAL					120

(1) Linear or areal extent of habitat; abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.

TABLE 9.4

Relative Marine Productivity and Environmental Sensitivity of the OCS Planning Areas

Planning Area	Overall Total Score
Hope Basin	349
North Aleutian Basin	327
St. George Basin	281
Norton Basin	280
Cook Inlet	272
Shumagin	265
Kodiak	264
Beaufort Sea	261
Washington-Oregon	256
Central Gulf of Mexico	254
Northern California	239
Gulf of Alaska	235
South Atlantic	230
Straits of Florida	228
Central California	227
Southern California	213
North Atlantic	209
Eastern Gulf of Mexico	208
Chukchi Sea	204
Mid-Atlantic	198
Western Gulf of Mexico	180
Navarin Basin	131

READEX FICHE

The results of this analysis are consistent with available information on the relative sensitivity of the resources to spilled oil. The results are also consistent with the current concepts of relative sensitivity of coastal and marine habitats (COPRDM, 1981; NRC, 1985). This is most clearly shown for the Navarin Basin where coastal habitats are negligible. In addition, the presence of high populations of sensitive biota (coastal and marine birds, marine mammals, whales, juvenile fish and shellfish) are the major factors supporting the high overall scores of the Alaskan planning areas. The ecological component which has the least effect on the overall scores is marine habitats. This results from the assumption that spilled oil cannot be transported in significant amounts from the surface of the ocean to most benthic commuities. The most sensitive marine habitats that could be affected are submerged vegetation and coral reefs. These habitats do not occupy a significant portion of any planning area.

Several commenters criticized the analysis of relative marine productivity and environmental sensitivity because of dissatisfaction with the results. In particular, the scores for marine habitats were criticized because the sensitivity of marine habitats in many diverse planning areas were scored the same due to lack of data. However, this lack of data on areal extent of marine habitats is not considered critical as most marine habitats are judged to have low sensitivity to spilled oil (Appendix I-2) and therefore, are scored equally.

The method used to generate Overall Total Scores was modified to ascertain the significance of having equal scores for marine habitats in diverse planning areas. The ranking of planning areas as to their relative marine productivity and environmental sensitivity was determined both as a composite of the individual scores for coastal habitats, marine habitats, and biota (Table 9.4) and for coastal habitats and biota without marine habitats (Table 9.5). The final order of planning areas is practically identical whether marine habitats are considered or not. As stated previously, scores with small differences between them should be viewed as relatively equal. Thus, the model is not sensitive to the lack of data on areal extent of low sensitivity marine habitats.

The results of this analysis should not be construed as indicating the level of impacts expected as a result of OCS development. In this analysis, sensitivity is determined from the likely response of the resource to the environmental perturbation without consideration of risk, likelihood of adverse impact, or vulnerability. Thus, the sensitivity ratings represent a conservative analysis. Additional factors would need to be considered to determine the expected level of impacts in a planning area from OCS oil and gas operations. These factors include the projected amount of hydrocarbon resources, their probable location within the planning area, the number and trajectory of hypothetical oil spills, and the location of possible spill sites, among others.

A high overall score or the presence of many sensitive resources in a planning area does not necessarily imply a high level of adverse effects from OCS development. Even those areas ranked with relatively low scores possess sensitive resources which will require consideration of specific environmental impacts at the sale stage and evaluation to determine the need for special protective measures.

TABLE 9.5

Relative Marine Productivity and Environmental Sensitivity of the OCS Planning Areas Calculated as the Sum of the Scores for Coastal Habitats and Biota

Planning Area	Score
Hope Basin	293
North Aleutian Basin	281
Cook Inlet	226
St. George Basin	222
Norton Basin	217
Kodiak	217
Shumagin	215
Beaufort Sea	211
Washington-Oregon	211
Central Gulf of Mexico	209
Northern California	194
Gulf of Alaska	186
South Atlantic	184
Straits of Florida	183
Central California	182
Southern California	168
North Atlantic	162
Eastern Gulf of Mexico	156
Chukchi Sea	155
Mid-Atlantic	153
Western Gulf of Mexico	135
Navarin Basin	86

The principal commenters on Appendix I of the Draft Proposed Program were the Natural Resources Defense Council (NRDC), the U.S. Environmental Protection Agency (EPA), and the National Oceanic and Atmospheric Administration (NOAA).

The NRDC expressed its greatest concerns about the marine productivity analysis and the rationale for lowering the productivity class of the North Aleutian Basin and the St. George Basin. Additional scientific information has been presented in Appendix I to demonstrate the basis for this action. The data presented clearly support the lower annual productivity. The NRDC comments will not lead to major changes in the conclusions of the analysis.

The EPA also expressed concern about the North Aleutian Basin and the St. George Basin productivity figures. The additional information presented in Appendix I should make clearer the MMS's rationale for the lowering of the productivity class of these planning areas. The EPA also presented a lengthy discussion of the complexities of the sensitivity analysis and alternative approaches. These approaches have been reviewed. The most easily implementable of these suggestions would be counter to the advice provided by the Scientific Committee of the OCS Advisory Board. The EPA suggestions would also make the analysis extremely complex and difficult to follow. Many of the suggestions, such as discussions of ecosystem interactions, are more appropriate to sale-specific EIS's.

The NOAA provided some clarification and qualification of productivity and sensitivity data used in the social costs analysis (Appendix G). As appropriate, this information in incorporated into Appendix I.

II.C. Equitable Sharing of Developmental Benefits and Environmental Risks

Section 18(a)(2)(B) requires that the Secretary base the timing and location of OCS exploration, development, and production on a consideration of, among other things, an

> ". . . equitable sharing of developmental benefits and environmental risks among the various regions."

Compliance with this requirement involves four key elements which will be addressed in this section: 1) the identification and presentation of developmental benefits and environmental risks; 2) the description of their actual sharing among the various regions; 3) the discussion of the concept of equitable sharing; and 4) the discussion of how the "consideration of . . . an equitable sharing. . ." is to be reflected in the scheduling of OCS lease sales.

In California v. Watt (II) (at 594), the court upheld the sufficiency of the analysis under section 18(a)(2)(B) which was presented in the SID for the 1982 leasing program. The analysis presented here uses the same approach, but is somewhat expanded.

Distribution of Benefits and Costs to Regions

The developmental benefits which will be analyzed in this section are the economic benefits which comprise the net economic value of production as described in Part II.B.1 and Appendix F. The environmental risks which will be discussed in this section are the social costs which are analyzed in Part II.B.2 and Appendix G.

Estimates of both economic benefits and social costs have been calculated on a planning area basis. These estimates are shown in Tables 3 and 7, respectively. While we can attribute certain benefits and costs to activity in a particular planning area of the OCS, how these benefits and costs are shared by the population onshore is not as obvious.

The court upheld the Secretary's consideration of the equitable sharing of the developmental benefits and environmental risks among the people of seven regions comprised of one or more coastal States in addition to the sharing among OCS planning areas. For this third 5-year program, basically the same seven regional units are also used, as follows:

Region I	-	Maine, New Hampshire, Massachusetts, Rhode Island, Connecticut, New York, New Jersey, Pennsylvania, Delaware, Maryland, Virginia
Region II	-	North Carolina, South Carolina, Georgia
Region III	-	Florida
Region IV	-	Texas, Louisiana, Mississippi, Alabama
Region V	-	California
Region VI	-	Washington, Oregon
Region VII	-	Alaska

The alternative of limiting regions to individual coastal States in all cases would make the analysis less informative. Because there is more uncertainty in estimating the environmental risks borne by individual States as opposed to those borne by the regional grouping in Regions I, II, IV, and VI, the regional approach has been retained in those cases. Where that limitation does not apply, however, single States have been treated as regions--as in the 1982 analysis (e.g., Regions III, V, and VII). It should be noted that Regions V and VI share some of the environmental risks arising from production offshore Alaska (see Appendix G). It should also be noted that Pennsylvania has been added to Region I. While Pennsylvania has no coastline directly adjacent to the OCS, Pennsylvania is defined as an affected State in 43 USC 1331 and 30 CFR 256.14.

Equitable Sharing and the Scheduling of OCS Lease Sales

Further discussion of equitable sharing occurred in the court's review of whether the 1982 leasing program was based on the factors listed in section 18(a)(2). It should be noted that the court did not define a standard of equitable sharing of developmental benefits and environmental risks which the Secretary was to achieve. Rather, the court sanctioned the Secretary's choice of a program which scheduled sales so as to be conducive to an equitable sharing of environmental risks among OCS regions.

In its opinion, the court held that in some circumstances it was appropriate to determine the location of sales in various planning areas on a basis other than relative net social value. Net social value is the measure of the overall value of oil and gas production to the Nation calculated by subtracting the social costs of such production (analyzed in Part II.B.2 and Appendix G) from its net economic value (analyzed in Part II.B.1 and Appendix F).

In particular, the court found that it was appropriate to schedule sales so as to expedite exploration in frontier areas (California v. Watt (II) at 599). Thus, leasing need not be scheduled in a manner that strictly reflects the projections of high value and potential for discovery in higher net social value areas in contrast to frontier areas. One basis for such an approach is the recognition that net social value estimates are only approximate indicators of what will result from OCS leasing. As was discussed in Part I, many effects are not quantifiable and thus cannot be included in the net social value calculation. In addition, actual hydrocarbon deposits may well prove to be distributed quite differently than as predicted by today's best estimates. Indeed, the court also recognized in a different but still relevant context that ". . . the Secretary realized that the cost-benefit analysis [i.e., the calculation of the net social value of planning areas and alternative schedules] should be used only for generalized conclusions. He did not think that the analysis would provide an adequate basis for making distinctions between planning areas" (California v. Watt (II) at 605).

In light of the court's opinion, the factors which need to be considered in making a determination about the equitable sharing of developmental benefits and environmental risks include numerous significant factors not under the control of the MMS to wit: the natural distribution of oil and gas resources among the areas of the OCS; the history of development of technology for oil and gas exploration, development, and production; the history of industry exploration and production strategies in State waters as well as the OCS; and the congressional and injunctive constraints which have been imposed on OCS leasing. The MMS's estimates of the natural distribution of economically recoverable oil and gas can be found in Appendix E. A brief summary of the history of leasing offshore can be found in Appendix F.

The fact that the court sanctioned the scheduling of more sales in frontier areas than would result from relative net social value alone has the further implication that the equitable sharing sought by the OCSLA, as amended, has to be interpreted in light of the overall purposes of the OCS Lands Act Amendments (OCSLAA), the first of which is "to achieve national economic and energy policy goals, assure national security, reduce dependence on foreign sources, and maintain a favorable balance of payments in world trade" (OCSLAA section 102(1)). In this context, the court explicitly upheld "...the Secretary's interpretation of the congressional intent to expedite offshore lease sales, particularly in frontier areas" (California v. Watt (II) at 599), emphasis in the original). It is also clear that the equitable sharing of developmental benefits and environmental risks is one among a number of factors whose consideration is mandated by section 18 of the OCS Lands Act.

Thus, the court upheld the grouping of OCS planning areas by their relative net social value as the general basis for scheduling OCS lease sales. The court also provided, however, for the modification of the net social value basis of scheduling sales with respect to frontier areas so that the regional contribution to the achievement of the overall purposes of the OCSLAA could be made more equitable. The full discussion of the scheduling of sales in Part III of this SID reflects the court's interpretation cited just above.

It was, however, in this context that the Draft Proposed Program received several comments from State and local governments, and public interest groups. Some of the commenters believed that equitable sharing, as they interpreted it, had been eroded and that their particular region or jurisdiction is facing unwarranted burden or environmental risk given the proposed leasing schedule, or because limitations on leasing in other areas creates pressure for greater leasing in their area. In particular, the letters from the California Legislature and from several California localities commented that leasing is objectionable, or that the leasing schedule off California is too close and too ambitious and that costs and risks of OCS activities contemplated in the leasing schedule off California did not reflect adequate concern for equitable sharing. This view was shared by Greenpeace, among others. In contrast, the letters from Texas and Louisiana, while supportive of leasing, noted that prohibitions or moratoria in other regions (California and North Atlantic) mean that there will be more OCS activity off their shores than would otherwise be the case, and that the objective of equitable sharing therefore will not be met.

In evaluating these comments, it should be kept in mind that equitable sharing should be viewed from a national perspective, taking into account the benefits that would occur as well as the risks to individual areas. Further, in balancing objectives the program requires as one consideration focusing on acreage with the highest economic value and industry interest among the planning areas. But this is not without full regard for environmental risks and the need to explore frontier areas.

Developmental Benefits and their Distribution

Developmental benefits are largely captured for subsequent distribution in the form of Federal revenues and to a lesser extent in the form of corporate profits. Within each region, some individuals and firms whose labor, land, materials, equipment, or other factors of production are used in OCS development regard the purchase of those resources as a benefit. In this respect, OCS production can

result in development of the kind that States and localities often seek under a variety of local, State, and Federal development programs. From the viewpoint of the Nation, however, the costs of these inputs are subtracted from production revenues in estimating net economic value.

In the context of equitable sharing of benefits among regions, it is worth noting that the States and localities can use tax policies and user fees to capture some of these developmental benefits to pay for the additional public services which may be required by any additional population attributable to OCS development. In fact, it was in this context, with particular regard to perceived infrastructure costs burdening local governments as a result of OCS activities off their jurisdictions that numerous comments were received from local governments and public interest groups and the issues was discussed at the April 1985 meeting of the OCS Policy Committee. This issue is treated in Appendix G and in Part II of the SID, where infrastructure costs are included in social costs. However, while these costs may be real, they do not come without benefits. Indeed, the demands for additional public services as a result of OCS activity comes from increased economic activity and employment that increase the output and income of the locality and are subject to the taxing decisions of the State and the affected localities. While it is recognized that the incidence of costs and benefits may not be perfectly matched, the same may be said of the impact of other major economic or institutional changes, such as the opening of a new automobile plant. The net effect, regionally and nationally, is that economic benefits usually exceed social costs. In Alaska, however, benefits may be lower than in other regions because fewer OCS workers may take up residence in local communities.

The sharing of benefits among the populations of coastal States varies depending upon the form of the benefit. Most developmental benefits are captured for subsequent distribution in the form of Federal revenues from lessees' cash bonus payments, rentals, royalties, income taxes, and other sources. There are a variety of ways to view how the benefits derived from increased Federal revenues would be shared. From one perspective, they would be distributed in about the same way Federal tax payments are collected because without OCS revenues the Federal Government would have to collect equivalent receipts through more taxes to sustain a given level of Federal expenditures. From another perspective, the distribution would be proportional to population because Federal programs benefit the public in general. A third perspective would distribute the benefits in proportion to Federal funds provided to State and local governments. All three ways of sharing benefits could be considered to be equitable because the resources of the OCS are managed by the Secretary on behalf of the public as a whole.

Benefits that arise in the form of corporate profits are distributed to people directly or indirectly in the form of stock dividends or the value of company stock. This distribution tends to be quite wide nationally speaking--it is certainly not likely to be concentrated in coastal areas. Thus, the distribution of company benefits is not unlike the distribution of Federal benefits. On the other hand, many of the perceived benefits from the purchase of factors of production used in OCS development tend to fall within the coastal areas providing the labor and materials used offshore. However, neither of these forms of benefit is likely to be large in comparison to the increases in Federal revenues. For these reasons, consideration of an equitable sharing of developmental benefits in this section is based primarily on the distribution to the various regions of benefits that are captured in the form of Federal revenues.

Table 10. Three Approaches to the Estimated Regional Distribution of Approximately $40 to $92 Billion Variation of Net Economic Value (N.E.V.) Resulting from Production of all Estimated Leasable Resources Unleased as of January 1987/1 (Dollar amounts in billions)

Regions/2	Region's Share of Total Federal Tax Payments/3	Resulting Share of N.E.V.	Regions's Share of Total U.S. Population/4	Resulting Share of N.E.V.	Region's Share of Total Federal Grants/5	Resulting Share of N.E.V.
I	28.0%	$11.1-25.8	25.4%	$10.1-23.4	29.0%	$11.5-26.7
II	5.0	2.0-4.6	6.4	2.5-5.9	5.5	2.2-5.1
III	4.4	1.8-4.1	4.6	1.8-4.2	3.0	1.2-2.8
IV	11.1	4.4-10.2	11.4	4.5-10.5	8.7	3.4-8.0
V	11.8	4.7-10.9	10.7	4.3-9.9	9.9	3.9-9.1
VI	3.0	1.2-2.8	3.0	1.2-2.8	2.9	1.2-2.7
VII	0.3	0.1-0.3	0.2	0.1-0.2	0.6	0.2-0.6

/1 Net economic value was calculated on a planning area basis (see Part II.B and Appendix F). Net economic value was allocated to the adjacent coastal regions in proportion to each region's share of the national total in three specific categories: the region's share of total Federal tax payments; the region's share of population; and in proportion to total Federal intergovernmental grants. The estimated regional share of total net economic value for this table was calculated by multiplying the total net economic value for all planning areas by each region's proportional share (expressed as a percentage) of each of the three variables in the table. The variation of total net economic value equals about $40 to $92 billion. Thus, Region I's share of the total N.E.V., if the distribution were based on its share of total Federal tax payments, would be 28 percent, or $11.1 to $25.8 billion. Regional percentages total less than 100 because only coastal States are included in the calculation.

/2 Regions are--I. Maine, New Hampshire, Massachusetts, Rhode Island, Connecticut, New York, New Jersey, Pennsylvania, Delaware, Maryland, Virginia; II. Morth Carolina, South Carolina, Georgia; III. Florida; IV. Texas, Louisiana, Mississippi, Alabama; V. California; VI. Washington, Oregon; and VII. Alaska.

/3 Source: Tax Foundation; Tax Features; April, 1984.

/4 Source: U.S. Department of commerce; Bureau of the Census; Estimates of the Population of the United States to August, 1983; Series P-25; September 1983.

/5 Source: U.S. Department of Commerce; Bureau of the Census; Federal Expenditures By State for Fiscal Year 1983; March 1984.

Table 10 shows how the total net economic value of the OCS oil and gas resources would be distributed under each of the three perspectives suggested above. There are relatively few differences among the three. The one exception is that Alaska's share of Federal grants to State and local governments is two to three times greater than its share of tax payments and population.

Environmental Risks and their Distribution

As stated earlier in this section, environmental risks are based on the analysis of social costs in Appendix G. While net social costs measure the estimated cost of producing an area's leasable resources to the Nation as a whole, they do not indicate the distribution of costs and in particular what the costs are to residents of each onshore area adjacent to the planning area.

The distribution of costs among the population tends to be skewed toward residents of coastal States. These people are more likely to be adversely affected by OCS development than inland residents.

To assess the costs borne by residents of coastal States adjacent to OCS areas resulting from the production of the leasable resources unleased as of January 1987, estimates were developed of regional cost. Regional cost as defined in Appendix G is a measure of the costs borne by the users of and onshore residents adjacent to an OCS planning area from OCS production in that area. The regional costs in Table 11 have been estimated by subtracting from the gross social cost associated with OCS production in an area, the compensation payments paid to residents for oil spill damages (assumed to be 50 percent of oil spill losses), and for commercial gear conflict losses (assumed to be 60 percent of all losses). Also deducted from the gross social cost associated with OCS production in an area are the costs avoided because OCS oil production in an area reduces oil imports into that area, and hence imported oil-related spills.

The production of OCS oil, though it may result in oil spills, also reduces the amount of oil imported and thus reduces the spills that would occur from tankers carrying imports in U.S. coastal waters. While the social cost analysis does not assume the backing out of imported oil by domestic natural gas production, it should be noted that OCS exploration and development can lead to the production of natural gas resources as well as oil. In 1984, about 25 percent of domestic production of natural gas was from the OCS. The discovery of natural gas resources can increase the beneficial economic and environmental effects of backing out imported oil or can result in additional benefits for two reasons: (1) OCS gas production can displace some imported oil thereby reducing imported oil-related spills; and (2) the greater availability of more OCS natural gas may lead to fuel switching from oil to natural gas, which is a cleaner-burning fuel. This effect can in turn be enhanced by the fact that the rollover of capital stock which often occurs during fuel switching results in a general upgrading of the level of efficiency with which fuel is used.

It should be pointed out that Table 11 indicates that the Gulf of Mexico Region is estimated to incur higher costs in this analysis than was estimated to be the case in the 1982 analysis. However, Table 10 indicates that the benefits which accrue to the Gulf of Mexico Region far outweigh those costs--as is the case for all Regions. In addition, as discussed above in this section, consideration of the scheduling of OCS lease sales in frontier areas further addresses the requirements of section 18(a)(2)(B) with respect to the equitable sharing of costs

Table 11. Distribution of Range of Social Costs by Region from Production of All Estimated Leasable Resources Unleased as of January 1987 (Millions of 1987 Dollars)

Regions	Regional Costs/a
I. Maine, New Hampshire Massachusetts, Rhode Island, Connecticut, New York, New Jersey, Pennsylvania, Delaware, Maryland, Virginia	-1.29[b] to -1.77[b]
II. North Carolina, South Carolina, Georgia	0.75 to 1.35
III. Florida	5.84 to 8.07
IV. Texas, Louisiana, Mississippi, Alabama	27.90 to 17.29
V. California	24.47 to 31.42
VI. Washington, Oregon	-0.17[b] to 0.76
VII. Alaska /c	4.31 to 28.52

/a The regional cost is estimated on a planning area basis as the gross social cost estimated to result from the production of that area's resources minus compensation pursuant to provisions of the OCS Lands Act Amendments of 1978 for potentially resultant oil spill and commercial fishing gear conflict losses, and minus the social cost avoided when oil production in the area backs out oil imports to the area (see Appendix G). Regional costs are calculated to include the costs associated with transshipment of oil produced in other OCS areas to or through that one OCS area. These planning area figures are allocated as follows: where a Region's coastline corresponds to one or more planning areas, for example, California, the total costs from the adjacent planning areas are allocated to the Region by adding them together; where adjacent planning areas do not coincide with State offshore boundary extensions, costs are allocated to Regions in proportion to their State coastline mileages.

/b A negative estimated regional cost, e.g., $-1.29 million dollars, indicates a gain rather than a loss in those values analyzed. Such net benefits result and accrue to the residents of the States adjacent to the planning area when the regional costs associated with development of the area's resources are less than the oil spill costs foregone from "backing out" foreign crude oil imported in tankers.

/c The wide variability in regional costs for Alaska occurs because only Navarin Basin has leasable resources at the $19 per barrel starting price. See Table 8 in Appendix F.

vis-a-vis mature production areas such as the Gulf of Mexico. Finally, in the context of the benefits to the Nation as a whole, Tables 1, 2, and 3 make clear the loss to the Nation which could result from unduly restricting oil and gas leasing in the Gulf of Mexico.

In conclusion, the developmental benefits of OCS leasing are shared widely while the environmental risks are concentrated in regions adjacent to the areas of the OCS in which most of the unleased oil and gas resources are expected to be leased and produced. The uneven burden of environmental risk should be reduced substantially by compensation that will be provided to those suffering damages from oil spills and commercial fishing gear losses. Further reductions in the unevenness of environmental risk could be achieved by increasing compensation, by imposing stricter controls or stipulations, or by restricting leasing in areas of higher environmental risk. As noted above, however, the court found that restricting leasing in frontier areas can lead to an inequitable sharing of environmental risks (California v. Watt (II) at 599). In addition, restrictions would need to be substantial in order to change markedly the distribution of environmental risk. Such restricted leasing would, however, substantially reduce benefits to the Nation as a whole.

II.D. Balancing Considerations

Section 18(a)(3) requires that:

> "The Secretary shall select the timing and location of leasing, to the maximum extent practicable, so as to obtain a proper balance between the potential for environmental damage, the potential for the discovery of oil and gas, and the potential for adverse impact on the coastal zone."

In California v. Watt (II) (at 606), the court upheld the cost-benefit analysis used in the formulation of the July 1982 5-Year OCS Oil and Gas Leasing Program as a means of compliance with section 18. In that 1982 analysis, as in the current analysis, the general interpretation of this requirement is that there is a presumption that an area should be included on the schedule if the expected benefits of oil and gas activities there exceed the expected costs, and that the most valuable areas should be offered first and most frequently. Estimates of the benefits from discovery and production of oil and gas and of the social costs, including a consideration of the factors listed in section 18(a)(2), have been calculated as discussed in Part II.B and Appendices F and G. These estimates have been used to calculate estimates of the net social value by planning area.

Net social value is the difference between the net economic value and the social cost estimated for total production of an area's unleased leasable resources, assuming that all are leased as of January 1987 and developed in the narrowed timefram thereafter. Table 12.1 displays the variation of estimated net social value by planning areas for the $19 to $29 range of starting oil prices. Table 12.2 balances benefits and costs on a per barrel basis for low value areas for which the method used for Table 12.1 was not applicable.

The presumption that areas with positive net social value estimates are to be included on the schedule is subject to modification based on the qualitative information not included in the quantitative net social value calculation. Such qualitative information appears in Part II.A, Part II.B.3, and Appendices B, C, H, I, and J. Further qualitative information will be contained in the EIS.

Careful examination of section 18(a)(3) and the methods used in the calculation of net social value indicates that the three considerations to be balanced ("the potential for environmental damage, the potential for the discovery of oil and gas, and the potential for adverse impact on the coastal zone") are not mutually exclusive. For example, there is an overlap between the potential for adverse impact on the coastal zone and the potential for environmental damage. Also, increased domestic production of OCS oil and gas can cause environmental damage and adverse impacts on the coastal zone--but can also reduce tankered imports of oil and thus reduce the potential for environmental damage and adverse impact on the coastal zone. The discovery of OCS natural gas in particular has the added potential for environmental and efficiency improvement, as discussed above with respect to equitable sharing. Furthermore, the beneficial effects which rigs can have as fishing reefs in some areas also shows that there can be gains which can offset to some extent the potential social costs of production.

It is worth reiterating that the section 18 analyses have been conducted such that the net economic benefits of leasing tend to be understated and the social costs of leasing tend to be overstated. In addition, it is noteworthy that even if social costs were 17 times greater, net social value would remain positive for all the areas listed.

Table 12.1

Estimated Net Social Value of Total Production of Unleased Undiscovered OCS Oil and Gas Resources as of January 1987 by Planning Areas Showing Variation by Starting Oil Prices (@ $19 to $29 per barrel) /1

Planning Area	Column 1 Variation of Estimated Net Economic Value of Leasable Resources ($ 1987 Millions) (1A) @$19	(1B) @$29	Column 2 Variation of Estimated Social Cost of Producing Leasable Resources ($ 1987 Millions) (2A) @$19	(2B) @$29	Column 3 Variation of Estimated Net Social Value ($ 1987 Millions) (1A-2A) @$19	(1B-2B) @$29
Central Gulf of Mexico (E)	$17,860	$35,245	$40	$41	$17,820	$35,204
Western Gulf of Mexico (E)	14,506	31,299	29	29	14,477	31,270
Southern California (F-E)	3,975	9,088	17	20	3,958	9,068
South Atlantic (P-F)	839	3,022	3	5	836	3,017
Central California (P-G)	765	2,649	5	6	760	2,643
Northern California (P-G)	910	2,463	5	6	905	2,457
Eastern Gulf of Mexico (G)	675	2,379	5	6	670	2,373
Navarin Basin (F-G)	121	2,591	7	27	114	2,564
Mid-Atlantic (G)	198	723	1	2	197	721
Washington-Oregon (P)	207	454	*	1	207	453
Beaufort Sea (F-G)	*	678	*	6	*	672
St. George Basin (G)	*	464	*	3	*	461
North Atlantic (G)	85	258	1	1	84	257
Straits of Florida (P-F)	14	33	*	*	14	33
Chukchi Sea (P)	*	596	*	5	*	591
Gulf of Alaska (F-G)	*	33	*	*	*	33
North Aleutian Basin (G)	*	20	*	*	*	20
Norton Basin (F-G)	*	20	*	*	*	20
Kodiak (G)	**	**	**	**	**	**
Hope Basin (F)	**	**	**	**	**	**
Shumagin (VP)	**	**	**	**	**	**
Cook Inlet (G)	**	**	**	**	**	**

*Estimated to be less than 0.5 million $1987.

**Resources for these areas are estimated to be negligible (see Table 2), thus no production is expected, and social costs are estimated to be less than 0.5 million $198 (See Table 12.2 for the balancing of benefits and costs of OCS leasing and production f these areas).

/1 See Figure 1 of this SID and Appendix F for the basic assumptions and results of the n economic value analysis and Appendix G for the basic assumptions and results of the social cost analysis. The planning areas are ordered in this table by net economic value @ $24/bbl.

In parentheses after each planning area is the evaluation of the grid coverage/quality of geologic and geophysical data for regional resource estimates for that planning area: E = Excellent; G = Good; F = Fair; P = Poor; and VP = Very Poor (see Appendix

Table 12.2

Balancing of Benefits and Costs
in Low Value Planning Areas /1

	Estimated Net Economic Value Per Barrel (Appendix F, Table 6A)	Estimated Social Costs Per Barrel (SID Table 8)
Cook Inlet	$1.44	$0.02
Shumagin	1.34	0.01
Kodiak	1.25	0.01
Hope Basin	0.68	0.01

/1 This table indicates the estimated balance of costs and benefits for planning areas estimated to have some developable resources, but only negligible leasable resources. Since the balancing analysis presented in Table 12.1 depends on the presence of estimated leasable resources in a planning area, a different method had to be used to estimate the balance of costs and benefits of OCS leasing and production for these four areas.

This table is based on the assumptions that if some or all of the developable resources in these areas were leased, their expected private value (the after-tax net present value for the bidder) would have to be equal to or greater than zero; that--on the low side--private value is equal to zero for each of those planning areas; and that the starting oil price is $24/bbl. (See Appendix F.)

Furthermore, both the total benefits and the costs are the result primarily of the resource potential of an area. There are no areas in which the estimated resource potential is substantial while the estimated costs of environmental damages and adverse impacts on the coastal zone are greater than the estimated benefits. On the contrary, in every planning area for which there are estimated leasable resources, estimated net economic value is at least 17 times larger than the estimated social costs. Areas of low resource potential have low benefits and even lower costs. Should such areas turn out to have more oil and gas than estimated, both the benefits and the costs would be greater than estimated. Still, the estimated benefits (see Tables 5, 8, and 12.2) would exceed the estimated costs. Thus, areas in which the estimated resource potential and estimated economic benefits are low to negligible should not be regarded as areas in which the costs exceed the benefits.

The timing and location of sales in the alternative schedules presented in this SID depends on numerous considerations which are discussed in connection with the decision options in Part III of the SID.

The court in California v. Watt (II) (at 712) specifically upheld the scheduling of lease sales on the basis of section 18 interests other than relative net social value alone. Indeed, in this context it should be noted that section 18(a)(3) specifies that one of the three elements to be balanced is "the potential for the discovery of oil and gas" (emphasis added). The great dependence of knowledge about the location and size of oil and gas deposits on drilling information needs to be recognized in the use of the net social value rankings which are in turn based on resource estimates. Resource estimates generated by the Government and by private parties are subject to substantial uncertainty especially where there is a paucity of seismic and drilling information available for an area (see Appendix E). This makes resource estimates about frontier areas especially uncertain. It is quite possible that estimates of resource potential based on very little data for a frontier area will turn out to be much lower than estimates based on more intensive seismic data. The collection of seismic data is the first step in the process leading to discovery of oil and gas. It results primarily from investments by firms planning to bid in scheduled lease sales. The scheduling of a sale for a low potential frontier area for which little data are available is one way to expedite a more intensive evaluation of its resource potential. Indeed, one of the purposes of the 1978 OCS Lands Act Amendments is to "insure that the extent of oil and natural gas resources of the OCS is assessed at the earliest practicable time" (section 102(9)). Consequently, although resource estimates are our best indicator of where the search for oil and gas should be focused, it is reasonable not to rely on the resulting net social value calculations alone in scheduling sales in frontier areas.

Planning areas have also been analyzed in terms of relative environmental sensitivity and marine productivity (see Part II.B.3 and Appendix I). To the extent possible, these considerations are reflected in the net social value rankings. However, since many of the environmental considerations can only be viewed in qualitative terms, the environmental sensitivity and marine productivity rankings need to be reviewed separately, as well as being an input to the estimation of net social value.

In addition to being used in the context of the factors discussed above, the net social value estimates are not used directly, but are used as a basis for the

formation of groups of areas within a range of estimated net social value, as appears below. Such an approach further guards against overreliance on the the absolute values of the net social value estimates, whose limitations have been described above in Part I and in Appendices F, G, and S.

The relative net social value estimates displayed in Table 12.1 can be used to divide the planning areas into the following three groups, based on magnitude:

High	Central Gulf of Mexico, Western Gulf of Mexico.
Intermediate	Southern California, South Atlantic, Central California, Northern California, Eastern Gulf of Mexico, Navarin Basin, Mid-Atlantic, Washington-Oregon, St. George Basin, Beaufort Sea, North Atlantic, Straits of Florida, Chukchi Sea, Gulf of Alaska, North Aleutian Basin, Norton Basin.
Low	Kodiak, Hope Basin, Shumagin, Cook Inlet.

The entire ranges of variation of net social value figures by oil starting prices within the Intermediate group (from less than $0.5 to $3,958 [@ $19/barrel] and from $20 to $9,063 [@ $29/barrel] [both in millions of $1987]) are substantially less than (i.e., less than 30 percent of) the net social value figure for the lower value area in the High group at the corresponding oil prices (Western Gulf of Mexico: $14,479 and $31,272, respectively [both in millions of $1987]).

The areas in the Low category include those which have been estimated to have negligible net economic value of leasing throughout the variations of starting oil prices, $19 - $29 (see Table 2). Kodiak, Hope Basin, Shumagin, and Cook Inlet, however, have been estimated to have some developable resources (see Table 4).

Part III identifies the numerous considerations which bear on the timing and location of sales. On the basis of net social value alone, the following timing would be consistent with this grouping:

--Areas in the High group are clear candidates for annual offerings.

--Areas in the Intermediate group have net social values substantially lower than the High group but all above $20 million ($1987) within the variation of starting oil prices of $19 - $29 per barrel. In this Intermediate range of areas, substantial discretion could reasonably be exercised within the bounds of section 18 considerations concerning the pace of leasing and the scheduling of sales. Sales in this group could be offered on a biennial, triennial, or less frequent basis, and could be scheduled as standard or frontier exploration sales. A frontier exploration sale is one for which industry interest would be polled by means of a Federal Register Notice several months prior to the scheduled beginning of the standard presale process.

--Areas in the Low group are candidates for standard sales, frontier exploration sales, or deferral for reconsideration in the formulation of the next 5-year program.

The Secretary will need to consider the conclusions which can be drawn from the net social value estimates and rankings, collectively with the information discussed above and the other qualitative information presented in this document and its appendices.

II.E. Minimum Bid and Bid Adequacy Review Considerations

Fair Market Value

Section 18(a)(4) of the OCS Lands Act requires the formulation of an OCS oil and gas leasing program consistent with the following principle:

> Leasing activities shall be conducted to assure receipt of fair market value for the lands leased and the rights conveyed by the Federal Government.

In litigation on the 1982 5-year program, the U.S. Court of Appeals for the District of Columbia Circuit was asked to determine whether the Secretary could meet the statutory requirement "to assure receipt of fair market value for the lands leased and the rights conveyed" by OCS oil and gas leases, in light of the fact that the "accelerated rate of leasing might ordinarily result in less intense competition and lower bids for some tracts." The court ruled that, despite the lower bids expected, "the proposed evaluation process, coupled with the Secretary's reasonable reliance on the integrity of the competitive bid process, is sufficient to assure that the fair market value is received. The statute requires nothing more." (See California v. Watt (II))

The structure of the lease market for the exchange of these rights between buyers and sellers is established by the OCS Lands Act. The act provides that oil and gas leases are to be sold by competitive sealed bidding and thus establishes the requirement of a competitive market structure to generate the value of OCS oil and gas leases. The decision to accept the high bid is based only on the amount of the bid (relative to the MMS quantitative measures of bid adequacy) given that the high bidder is qualified to conduct OCS operations (see Appendix K for a detailed discussion of fair market value).

The Natural Resources Defense Council and others, in their comments on the Draft Proposed Program included concerns about fair market value issues. Specifically NRDC contends that areawide leasing is not likely to lead to an efficient allocation of resources or the attainment of fair market value for the resources leased. They believe that the decline in per acre bonuses indicates that the Government did not receive a fair market value for the resources leased. They attribute this decline to a decrease in competition with areawide leasing, limited resources available to bid and to formulate bids, and the limited information about the tracts offered. NRDC's and others' concerns regarding the revenue effects of past areawide leasing are addressed in Appendix P, which analyzes both the tract selection and areawide leasing approaches.

In comments on the Draft Proposed Program, NRDC also expressed concern about the Department's ability to do an effective job of evaluating tracts for bid adequacy. Bid adequacy procedures originally adopted in conjunction with areawide leasing have been modified as a result of ongoing analysis of their use. As a result of these modifications, the percentage of tracts passed to "Phase 2" (of the bid adequacy procedures) for detailed evaluation, has increased from 33 percent to over 50 percent. In its March 26, 1985, report, "Interior Has Taken Steps to Improve the Adequacy of Data Used for Making (OCS) Leasing Decision," the GAO discussed the issue and made no recommendations. For the Proposed Program, Appendix K has been revised to include a complete description of the current bid adequacy review procedures with an explanation of how these procedures help to ensure the receipt of fair market value.

Another factor which NRDC believes contributes to the failure to attain fair market value is the Government's use of the cash bonus bid form of auction. NRDC proposes that alternative bidding systems be considered for their roles in ensuring the receipt of fair market value.

Alternative bidding systems have currently not been addressed in terms of their effects on competition and fair market value. Based on past analysis of these systems, the Department has found that the effects on competition have been negligible. (See: DOI, MMS: "Report to Congress on Fiscal Year 1983 Outer Continental Shelf Lease Sales and Evaluation of Alternative Bidding Systems", April 1983.)

Minimum Bid and Bid Adequacy Review

The competitive sealed bidding process of the OCS lease market is the market mechanism which generates a fair market value at a specific point in time (i.e., a sale). However, there are circumstances in the OCS lease market which could allow bids to be submitted which, without the exercise of a prudent assessment by the Government, could result in receipt of less than fair market value. Where information asymmetry exists, such as on drainage and development tracts on which the adjacent owner has privileged information, or on wildcat and proven tracts that involve development technologies unique or limited to selected companies, the corresponding bid may be skewed and other parties may choose not to bid. In order to assure fair market value as the law requires and the courts have interpreted, the Secretary has developed a set of procedures which reflect an understanding of the workings of the OCS lease market in generating values and bids. The Secretary has structured the procedures to assure receipt of fair market value by relying on the market to generate fair market value and by relying on Government evaluations to assure that market values being generated for certain categories of tracts are indeed fair; otherwise, the high bids are rejected and the tracts reoffered at a later date.

In July 1982, a Department-wide task force was established to develop and test various methods for determining bid adequacy in light of the Secretary's legal requirement to assure receipt of fair market value in conjunction with the leasing program proposed at that time. In February 1983, the Department adopted the recommended procedures of the task force. The procedures consisted of a two-phase bid adequacy process which used tract classification and actual bid data to determine which tracts required detailed analysis. Phase 1 includes market-oriented evaluation criteria for accepting some bids on some blocks and determining what other bids will receive further evaluation in Phase 2. Phase 2 uses tract value estimates from a discounted cash flow model as the basis for accepting or rejecting bids.

In 1982, the Department increased the minimum bid from $25 to $150 per acre and provided for reconsideration of the minimum bid level based upon experience. In conjunction with the two-phased procedures, the minimum bid may help to assure fair market value by substantially increasing the bonus amounts bid on many one-bid tracts. The minimum bid represents an across-the-board Government evaluation standard with which all high bids are compared--it provides the initial step in the overall bid adequacy screening process.

In 1984 and 1985, modifications were made to the OCS bid adequacy procedures to incorporate knowledge gained from their actual use in areawide lease sales. On the surface, there has been an observable overall decrease in the average bonus bid per acre in recent years. This trend actually began in 1982 in tract selection sales. There has also been an increase in the number of one-bid tracts. Analysis of these observations was made to assess their cause. While the per acre bonus declines have been due to a myriad of factors, the most significant ones appear to be the decrease in the expected price of oil and the overall quality and location of tracts being offered for lease. A 20 percent drop in the real world price of oil, along with projections of lower rates of future price growth, have significantly influenced the present value of tracts being offered. Further, the sale and leasing of tracts in areawide offerings have seen industry moving into deep-water, high-cost areas of mature OCS planning areas and into high-cost frontier areas--a trend which had barely begun when nomination-type sales were held. Market forces are operating to reflect these conditions.

Based on analyses, studies, and experience with the oil and gas leasing market, categories of tracts for which the bids may not assure fair market value are subjected to additional independent Government evaluation. All evaluations incorporate the use of the latest geological, geophysical, and economic evaluation methodologies and account for the inherent uncertainties of all the major variables. A detailed description of bid adequacy review procedures appears in Appendix K.

Part of the decision on the Draft Proposed Program was to review the question of whether the minimum bid level should be changed either in general or on a variable basis for different planning areas. Alternatively, the question was raised whether enlargement of the maximum tract size would achieve effects comparable to varying the minimum bid. Two of the eight topics presented for comment in the Federal Register Notice of March 22, 1985, pertain to these questions. The following comments were received on these topics:

Federal Register Notice Topic No. 6:

> Whether conditions such as the following concerning the level of the minimum bid would warrant varying the current minimum bid level of $150 per acre on a nationwide or planning area basis: (1) changes in economic conditions such as oil prices; or (2) potential effects on the number of tracts leased or the rate of exploration and development.
>
> The Department of Energy commented that they would support changes designed to encourage frontier exploration, but also observed that without compelling reasons to change the minimum bid level, it would be best to leave it as is for the sake of program stability.
>
> Alabama stated that the current minimum bid level is appropriate only for frontier areas and should be raised in high potential areas. Maryland commented that the minimum bid level should be adjusted, at least on a planning area basis, to take care of any contingencies that may arise. New Jersey communicated a willingness to explore with the Department of the Interior consideration of varying the current per acre bid level if it could be demonstrated that it would be an economic benefit to the Federal Government and encourage exploration.

North Carolina stated no objection to raising the minimum bid level, but would object to lowering it. Rhode Island endorsed establishment of different minimum bids for different planning areas. The State also suggested offering a limited number of tracts under a work commitment/fixed royalty bidding system. Virginia commented that the factors under consideration with this topic could have an effect on minimum bid level.

Chevron and Marathon commented that the current minimum bid is satisfactory for a 5,760 acre tract, but should be lowered for larger tracts. BP Alaska commented in favor of reassessing the minimum bid considering reduced expectations for future oil prices. ARCO encouraged elimination or reduction of the current minimum bid and recommended establishment of a minimum bid for each planning area at a level commensurate with exploration risk for that area.

Shell recommended lowering the minimum bid in all planning areas and pointed out that the bonus bid represents just one element of the total revenue received by the Federal Government as a result of the OCS program. They also commented that the minimum bid level should be low to offset risks and costs in frontier areas and make leasing and developing those areas viable. Tenneco suggested halving the current minimum bid in the Gulf of Mexico to enhance the economic viability of prospects on which the potential for hydrocarbons is less than that of leases offered in previous sales.

Sohio commented that generally the minimum bid level should be lowered, and recommended specific levels for certain planning areas and conditions. Texaco expressed opposition to the current minimum bid level and suggested that a range of $25 - $50 per acre be adopted on a nationwide basis. Exxon recommended that the minimum bid level be revised on a planning area and water depth basis. A figure of $50 per acre for Alaska planning areas and greater than 400' water depths was suggested, and a level of $75 per acre was suggested for the rest of the OCS.

The Lone Star Sierra Club chapter (Galveston, Tx.) stated that the minimum bid level should be tied to the economy by indexing, and difficulty factors such as deep-water and strong currents should be considered, but the minimum bid always should be enough to cover costs of the leasing program. The Florida Public Interest Research Group and Greenpeace expressed opposition to lowering the minimum bid level.

Federal Register Notice Topic No. 7:

Whether the tract size limit of 5,760 acres ought to be expanded; and whether enlargement of the maximum tract size is an alternative which would achieve effects comparable to varying the minimum bid.

The Department of Energy commented that they would support changes designed to encourage frontier exploration, but also observed that without compelling reasons to change the maximum tract size, it would be best to leave it as is for the sake of program stability.

Alabama stated that the maximum tract size should not be expanded for tracts in the 8(g) zone off Alabama, and sufficient data are not available to comment on expansion in areas beyond the 8(g) zone. Virginia stated they have no reason to advocate a change in tract sizes at this time. New Jersey communicated a willingness to explore with the Department of the Interior consideration of expanding the maximum tract size if it could be demonstrated that it would be of economic benefit to the Federal Government and encourage exploration. North Carolina commented that expanding the maximum tract size may be appropriate for frontier areas, but not for highly productive areas.

BP Alaska, Shell, Texaco, Amoco, and Exxon did not support expanding the maximum tract size. BP Alaska commented that larger tracts might lower competition. Shell recommended encouraging the formation of exploration units rather than leasing larger tracts. Chevron, Sohio, and Mobil supported expanding the maximum tract size to tailor it to specific prospects. Chevron recommended sizes up to 23,040 acres in the Atlantic Reef Trend and West Florida Strait. Mobil recommended increasing the size of tracts in waters over 300 meters deep to 11,520 acres. Marathon commented that a larger tract size may be appropriate in low interest areas or areas where exploration and development costs are high.

The Florida Public Interest Research Group stated no objection to enlarging tract size to a reasonable economic production unit, providing the minimum bid level is raised to maintain the same price per acre. Greenpeace expressed opposition to expanding the maximum tract size.

MMS has also conducted evaluations of both the minimum bid and larger tract size issues:

1. Analysis of Minimum Bid Policies, Branch of Economic Studies, Offshore Resource Evaluation Division, June 7, 1985; and

2. Evaluation of Larger Tract Size Options, Branch of Economic Studies, Offshore Resource Evaluation Division, June 1985.

Both papers have been considered as part of the record for the development of the new 5-year program. The larger tract size paper is also discussed below and the minimum bid paper is summarized in Appendixes F and K, and is discussed in the decision options section of this SID.

The larger tract size analysis focuses on the possibility of modifying the current maximum tract size of 5760 acres as a means to stimulate industry activity in high-risk OCS areas by providing a new incentive for industry to explore these areas. The reasoning here is that, in high-risk, high-cost areas, the present tract size may not be appropriate to support investment costs even if a discovery were made. The Secretary has the authority, under section 8(b)(1) of the OCS Lands Act, to increase the maximum tract size (beyond 5760 acres) if a larger area is necessary to comprise a reasonable economic production unit.

In general, benefits of larger tract sizes include: a decrease in discovery risk; economies of scale; greater information value; and a reduction in production risk, if a discovery is made. Each of these benefits is described in the analysis. However, the analysis also details significant problems associated with increasing tract size, including the determination of a "reasonable economic production unit." Defining a "reasonable economic production unit" would be a complex task, because of the many factors which influence the determination and because these factors change through time and vary among areas. Additionally, the acquisition of the information would be costly and would need to be collected on a repeated basis. Another important factor to consider is that what is perceived to be a reasonable economic production unit, even for a given geologic prospect, is likely to differ among lessees. Therefore, even if the Government could identify a specific structure and define a reasonable economic production unit, lessees may not share the same view.

The implication of the analysis is that increasing tract size may not be the most efficient policy instrument with which to provide exploration incentives because of two major factors: complexities associated with trying to determine a reasonable economic production unit; and the fact that unitization is available to help lessees achieve economies of scale in exploration, development, and production. For these reasons, and because a significant number of public comments (including industry) indicated a preference for tracts no larger than 5760 acres, an option to increase tract size is not presented in this SID.

A decision option on minimum bid policy is developed, which includes a discussion of the effects of the minimum bid level on:

1. bidding and Government receipts;

2. the appropriate timing for the leasing and development of prospects in different OCS areas; and

3. promoting exploration in high-risk/high cost areas.

This decision option and a decision option for bid adequacy procedures appear in section III.C.

Part III Options for the Proposed Program

Section 18 provides for three successive stages of development of a new 5-year OCS leasing program prior to final approval. This Proposed Program stage is the second of those three. No final decisions on the new program will be made until after completion of the process set forth in section 18 and the National Environmental Policy Act and their implementing regulations.

III.A. Location and Timing Options for the Proposed Program

In the formulation of a leasing program, many location and timing considerations merge. Consequently, this section of the SID presents a number of location and timing issues in combined form.

The first category of location considerations in formulating the Proposed Program concerns the selection of a configuration of planning areas and boundaries. The second category deals with the scheduling of sales in the various planning areas.

A.1. Planning Area Configuration Options for the Proposed Program

The development of a new 5-year program calls for the consideration afresh of the whole OCS. The configuration of planning areas rests on a number of considerations: geological and geophysical data; leasing, exploration, development, and production history; environmental data; coordination with coastal governmental entities; mapping considerations; jurisdictional claims to the OCS and the Exclusive Economic Zone (EEZ); and administrative factors.

The March 1985 Draft Proposed Program divided the entire OCS into 26 planning areas which are basically similar to the areas adopted for the 1982 program, except for the following new features: the planning areas offshore California were reconfigured from two to three; a separate planning area was established for the Straits of Florida; the Eastern Gulf of Mexico and Beaufort Sea planning areas were reconfigured; and 128° W. longitude was proposed as the seaward boundary for the new Northern California and Washington-Oregon planning areas. The California planning areas were reconfigured to the following:

1. Southern California--the offshore area from the provisional boundary with Mexico north to the San Luis Obispo County/Monterey County line, between block rows N825 and N826. This would merge the Santa Maria area with the present Southern California area. This new area would contain approximately 436 miles of mainland coastline.

2. Central California--the offshore area north of the San Luis Obispo County/Monterey County line to the Sonoma County/Mendocino County line, between block rows N894 and N895. This new area would include two basins and would contain approximately 350 miles of mainland coastline.

3. Northern California--the offshore area north of the Central California area to the California/Oregon border. This new area would include the two northernmost basins and would contain approximately 286 miles of mainland coastline.

Comments

General: The State Department discussed the international aspects of planning area configuration, suggesting revision of the boundaries delineated for the North Atlantic, South Atlantic, Straits of Florida, Western Gulf of Mexico, Washington-Oregon, and Chukchi Sea planning areas. These suggestions have been incorporated into decision option 1-a. The Natural Resources Defense Council (NRDC) suggested that planning areas be more narrowly defined and requested an explanation of the proposed reconfiguration. A discussion of the environment of the planning areas as reconfigured will appear in the draft EIS for the new program.

Alaska: The National Oceanic and Atmospheric Administration (NOAA) expressed concern that several Alaska OCS planning areas may extend beyond foreseeable technology and economics and called for the environmental studies program to examine the deepwater areas closely before actually deciding to lease them. BP Alaska and the National Ocean Industries Association (NOIA) specifically endorsed the proposed configuration of the Beaufort Sea planning area.

Atlantic: New York and Rhode Island reiterated the desire to be able to review proprietary data from both the North Atlantic and Mid-Atlantic planning areas (see Option 1-b). Delaware reiterated a suggestion to reconfigure the boundary between the Mid-Atlantic and North Atlantic planning areas in a different way. Maryland, New Jersey, and Virginia stated their agreement with the proposed configuration of planning areas. Marathon Oil endorsed establishment of the Straits of Florida planning area, and Texaco endorsed the South Atlantic planning area. Florida expressed concern about making the Straits of Florida a distinct planning area. North Carolina found the planning areas to be appropriate, but expressed a concern for more study of the Straits of Florida planning area. Exxon supported the proposed configuration of all planning areas except the Straits of Florida, the separation of which they believe is of no practical value. The API shared this opinion of the Straits of Florida planning area. The Florida Public Interest Research Group stated they have no objection to the proposed configuration of planning areas, but are concerned by the creation of the Straits of Florida area.

California: The U.S. Environmental Protection Agency (EPA) requested additional discussion of the reconfiguration of the California planning areas. A discussion of the environment of the California planning areas will appear in the draft EIS for the new program.

The County of Santa Cruz submitted comments stating that the reconfigured planning areas will enable more comprehensive and accurate environmental assessment of the Central California Basin. The County of Ventura concurred with the March 1985 reconfiguration of planning areas. The City of San Francisco stated that the California OCS planning areas as reconfigured in March 1985 should allow more concentrated review of leasing issues. The County of San Luis Obispo submitted a resolution expressing support for the March 1985 reconfiguration of California OCS planning areas with the exception of expansion of seaward boundary limits. The March 1985 reconfiguration of California OCS planning areas was endorsed by NOAA. Chevron, Amoco, BP Alaska, Marathon, Shell, Texaco, Western Oil and Gas Association, American Petroleum Institute (API), and NOIA concurred with the proposed configuration of planning areas and specifically endorsed the reconfiguration of California OCS planning areas. Get Oil Out, Inc., stated that the reconfiguration of California OCS planning areas provides a more equitable leasing program.

On the other hand, the California Department of Justice stated that OCS planning areas are still too large and reiterated its request for eight planning areas offshore California. The same commenter also argued, however, that too many sales were scheduled offshore California. Thus, increasing the number of planning areas offshore a particular region of the U.S. must be considered in light of potential objections about the number of sales that would be scheduled for the region as a whole. The comment that the planning areas are too large to manage is also relevant to the question of potential deferrals of portions of planning areas, discussed below.

The California Coastal Commission objected to the establishment of three planning areas with the Santa Maria Basin placed in the Southern California planning area. They cited ecological criteria and planning burdens as the basis for objection. The California Department of Fish and Game recommended that the Santa Maria Basin be included in the Central California planning area or established as a separate planning area. The California State Lands Commission noted great biological and oceanographic differences within the proposed Southern California planning area due to moving its boundary northward. Several members of the Senate Rules Committee of the California Legislature submitted a letter making alternative proposals concerning the Southern California planning area.

Several California local governments noted the reconfiguration of California OCS planning areas in resolutions stating general opposition to the Draft Proposed Program. These include: Association of Monterey Bay Area Governments, County of Santa Cruz, County of Mendocino, City of Laguna Beach, County of San Mateo, County of Monterey, County of Sonoma, City of Morro Bay, County of San Luis Obispo, City of Santa Cruz, and City of Watsonville. The City of Pismo Beach submitted a resolution recommending reconfiguration of the California OCS by placing the Santa Maria Basin in a Central California planning area extending from Point Arguello to San Francisco Bay. The City of Los Angeles stated that enlarging the Southern California planning area will decrease the possibility of performing detailed environmental analysis of the area. The City of Monterey's comments included a statement by a member of the Board of Supervisors that the California OCS planning areas will still be too large. The City of San Clemente alleged that reconfiguration of California OCS planning areas increases the overall size of the area under consideration for lease.

The Marin Conservation League and the California Public Interest Research Group noted the reconfiguration of California OCS planning areas in a resolution stating general opposition to the Draft Proposed Program. The Environmental Center of San Luis Obispo County commented that the proposed reconfiguration of California OCS planning areas serves only to divide and dilute public input to the leasing process. The League of Women Voters of San Luis Obispo County commented that planning area boundaries have been extended beyond areas of technological capability. The Pacific Coast Federation of Fishermen's Associations commented that the proposed planning areas are too large. The Santa Lucia Sierra Club Chapter stated that California should be divided into four or five planning areas. A letter signed by Congressmen Mel Levine, Bill Lowry, and Leon R. Panetta stated that they hope the March 1985 reconfiguration of California OCS planning areas will facilitate more adequate environmental and economic impact assessments.

Gulf of Mexico: Florida opposed the expansion of the Eastern Gulf of Mexico planning area to include both the sensitive area south of 25° N latitude to 24° N latitude (near the Florida Keys) and the area east of 82° W longitude (offshore Monroe County, FL). Mobil Oil proposed moving the deepwater boundary between the Central and Western Gulf of Mexico planning areas west to represent an extension of the current Texas/Louisiana offshore shelf boundary.

Washington-Oregon: Oregon requested no leasing beyond 125° W longitude and Washington requested that sales be confined to the area of hydrocarbon potential. The discussion of subarea deferrals will respond to the comment from the State of Oregon, and the discussion of the presale process will apply to the comments of both Oregon and Washington that the OCS planning area adjacent ot them extends too far seaward. NOIA endorsed the 128° outer boundary of the Northern California and Washington-Oregon planning areas.

-Decision Options for the Proposed Program

Based on further review of planning area configuration and boundary issues, including a review of the comments on the Draft Proposed Program, the following decision options are presented for consideration.

OPTION 1-a Use the configuration of planning areas and boundaries adopted for the Draft Proposed Program, with minor adjustments recommended by the Department of State (described in Appendix N).

The boundaries selected for the Draft Proposed Program are depicted in Part I.A.5 of this SID. The minor adjustments recommended by the Department of State (listed below) do not alter those maps at the scale at which they are drawn.

North Atlantic: Extends South from the juncture of the territorial sea at 71° W longitude to 39° N latitude thence east to the juncture of an extension of the U.S.-Canada Maritime Boundary thence northerly along that line and the maritime boundary to the territorial sea thence following the territorial sea to the point of origin.

South Atlantic: East from the juncture of the territorial sea at approximately 35° N latitude to 70° W longitude thence south to 34° N latitude thence west to 72° W longitude thence south to 32° N latitude thence west to 74° W longitude, thence south to 31° N latitude thence west to 78° W longitude thence south to 28°17'10" N latitude thence west to the territorial sea limits thence north along the territorial sea to the point of origin.

Straits of Florida: East from the juncture of the territorial sea at 28°17'10" N latitude to 79°11'24" W longitude thence southwest along the line of U.S. jurisdiction to approximately 81°13' W longitude at 23°55' N latitude thence west to 83° W longitude thence north to the territorial sea abutting the Dry Tortugas thence east to the limits of the territorial sea thence along the territorial sea to the point of origin.

Western Gulf of Mexico: East from the territorial sea along the U.S.-Mexico Provisional Maritime Boundary to 93°26'42.19" W longitude thence along approximately 26° N latitude to approximately 91°55' W longitude thence north to approximately 27°55' N latitude thence generally west to approximately 93°25' W longitude thence northwest to the juncture of the territorial sea at approximately 93°50' W longitude thence along the territorial sea to the point of origin.

Washington-Oregon: West along a line extending from the territorial sea at approximately 42° N latitude to 128° W longitude thence north to the limits of U.S. jurisdiction thence northeast along the limits of U.S. jurisdiction to 48°29'37.19" N latitude at 124°43'33.19" W longitude thence due south to the territorial sea thence along the territorial sea to the point of origin.

Chukchi Sea: East from the U.S.-Russia Convention Line along 73° N latitude to 162° W longitude thence south to 71° N latitude thence east to the limits of the territorial sea thence generally southwest to approximately 68° 20' N latitude at 167° W longitude thence west to the U.S.-Russia Convention Line thence north to the point of origin.

The March 1985 California planning area reconfiguration satisfies several concerns noted in comments received on the Draft Proposed Program. The March 1985 reconfiguration combines all existing OCS oil and gas operations within the Southern California planning area, permitting a more realistic and accurate analysis of environmental effects. Also, in conjunction with the leasing schedule proposed in March 1985, the frequency of sales in each new planning area is reduced from one sale every other year to one sale every third year.

The seaward boundary of the Northern California and Washington-Oregon planning areas was set at 128° W longitude so as to comprise the area of hydrocarbon potential as estimated by MMS. MMS has reviewed this feature of the Draft Proposed Program and reaffirms the judgment that the official protraction diagrams included in these two planning areas contain acreage within the area of hydrocarbon potential. Likewise, the Eastern Gulf of Mexico area in the vicinity of the Florida Keys, south of 25° N latitude and east of 82° W longitude, is within the area of hydrocarbon potential. These areas are thus retained in the basic configuration of planning areas for this option. However, both the subarea deletion option and the presale process for specific sales provide ways of addressing objections to offering for lease acreage of concern to commenters.

OPTION 1-b Revise the boundary between the North and Mid-Atlantic planning areas.

This option is being retained in case a problem arises with the regulatory approach to providing New York and Rhode Island with the ability to review proprietary data concerning both the North and Mid-Atlantic planning areas. That approach was selected as part of the Draft Proposed Program and a proposed regulation is being prepared by MMS. Both States reiterated their interest in reviewing the data in question in their comments on the Draft Proposed Program.

This change would replace the previous boundary with a line which proceeds north along the 71st meridian to the northern edge of Official Protraction Diagram (OPD) NK 19-10, thence west along the boundary of NK 19-10 and NK 18-12 to the Federal/State boundary.

OPTION 1-c - Subarea Deferrals

Section 18(f)(1) of the OCS Lands Act provides the basis for the Secretary's consideration of "nominations for any area to be offered for lease or to be excluded from leasing." Requests for deferrals of about 100 specific geographic subareas or categories of subareas as part of the new 5-year program have come from a variety of parties. Appendix B lists all requests for deferral by States, localities, and other parties received in comments on the Draft Proposed Program. In addition, a document in the record of the development of the SID and EIS for the new program lists all subareas nominated for deferral in response to either the July 1984 or March 1985 Federal Register Notices in the new 5-year program as well as a number of Department of Defense and National Aeronautics and Space Administration use areas. That document describes the environment of the subarea, its resource potential, and the impacts which might be avoided were the subarea to be deferred from the new program. The outcome of consultations concerning OCS leasing offshore California will also be reflected in the new 5-year program.

Advantages and Disadvantages of Subarea Deferrals at the 5-Year Program Stage

On one hand, removing high conflict areas at the earliest stage of the leasing process could reduce controversy and litigation over them. In addition, deferrals of portions of planning areas could reduce the analysis burden in the presale process for all parties.

On the other hand, even if the prospect of leasing certain subareas is fraught with controversy, there are reasons for waiting until after the final 5-year program is issued before deciding on their deferral. The U.S. Circuit Court of Appeals for D.C. has upheld the phased nature of OCS decisionmaking, with the broadest decisions affecting whole planning areas to be made at the 5-year program stage and more specific decisions within planning areas to be made in the presale process.

Section 18 is designed to compare whole planning areas. No subarea deferrals from the midst of planning areas were made in the 1980 or 1982 programs. Neither Appeals Court opinion gives clear guidance on this issue. Given the interpretation of section 18 by the U.S. Court of Appeals for D.C. in California v. Watt (II), the requirement for a quantitative comparative analysis of planning areas significantly complicates the process of making a decision on subarea deferrals at the 5-year program stage.

If any subarea deferrals are made part of the Proposed Program, the quantitative comparative analysis of planning areas will be re-run based on the modified planning areas and the results presented for consideration for the decision at the Proposed Final Program stage. Given the way in which net social value rankings (economic benefits minus social costs) are grouped in order to structure decision options, the deferral of a substantial portion of the resources in a planning area could significantly affect its place in the 5-year program schedule options.

Subarea deferrals can short-circuit the extensive presale planning process including environmental analysis and consultation and can remove the possibility of reaching sale-specific accommodations and safeguards that could allow offering areas of concern.

Deferrals may be premature and may limit flexibility if made before the availablility of the geological and environmental information usually gathered during the presale process for a sale.

Subarea deferrals made at the 5-year program stage cannot be reconsidered for leasing for 5 years (unless a new 5-year program is developed--a 2-year process). This could have a dampening effect on information-gathering in areas which are deferred. Thus, subarea deferrals may, effectively, become permanent.

Comments on Special Consideration for Subareas/Subarea Deferrals

In addition to the requests for deferral of particular subareas mentioned above and summarized in Appendix B, a number of general comments were received. The Department of Energy commented that no subarea should be deleted from consideration until an adequate evaluation has been made of the oil and gas resource potential of the area.

Shell, Exxon, and Amoco stated opposition to establishment of special subareas subject to special considerations. Mobil and Sohio commented that frontier and deepwater areas or subareas should be given special treatment based on consideration of drilling results, economics, technology, and needs. Chevron suggested that all areas deeper than 3,000 meters be deleted from the 5-year program. Chevron also commented that portions of the Southern California planning area which are used for defense activities may require special consideration. Marathon stated that certain subareas should receive special consideration, but they should not be excluded from lease sales.

Subarea Deferral Decision Options

OPTION 1-c-i Make subarea deferrals at the 5-year program stage.

Four different approaches to deferrals are outlined below.

1-c-i-A Defer subareas based only on national security grounds--Department of Defense (DOD) and National Aeronautics and Space Administration (NASA) use areas--at the Proposed Program Stage

Section 102 of the OCS Lands Act Amendments provides that one of the purposes of the act is to "assure national security." In order to manage the resources of the OCS so as to contribute to that objective, a deferral decision could be made regarding DOD and NASA use areas only.

1-c-i-B Defer the following subareas at the Proposed Program stage.

(I) Defer eight subareas offshore California. These areas are displayed on the two maps which appear on the following pages. Other characteristics of these areas are as follows:

(a) The area off Pt. Reyes Wilderness - consists of 92 blocks and is consistent with the statutory prohibition against leasing in this area contained in section 11(h) of the OCS Lands Act.

(b) Pt. Reyes-Farallon Islands National Marine Sanctuary - consists of an area of 948 square nautical miles and is consistent with the sanctuary established by NOAA.

(c) The area in the immediate vicinity of Cordell Bank - consists of part of 8 blocks that encompass the 91 meter isobath of this area.

(d) The area offshore San Francisco Bay - consists of 16 blocks immediately outside San Francisco Bay.

(e) The areas offshore Monterey Bay - consisting of 95 blocks. These areas comprise an Area A which extends 10 miles from the California coast from just north of Monterey Bay to just south of Monterey Bay. In this 10 mile area a deferral would be made, consistent with the Secretary's statement in the Summer of 1985 and because of the potential small effect on the view from the coast. At 10 miles, a 260 foot high platform on a perfectly clear day would appear to be about 1/8 inch high and less than 1/8 inch wide. At that distance, most observers would not be able to distinguish whether the object was a platform or a ship. In Area B off Monterey Bay, the deferral is extended to include an additional area consistent with the Secretary's statement and because of current low industry interest. The combined areas extend 48 miles offshore.

(f) The areas offshore Big Sur - consisting of 449 blocks. These areas comprise an A and B zone for the same reasons as discussed with respect to the areas offshore Monterey Bay. The combined areas extend 131 miles offshore.

(g) Santa Barbara Ecological Preserve and Buffer Zone - consists of 15 full and partial blocks which were withdrawn from leasing by Public Land Order 4587 on March 21, 1969.

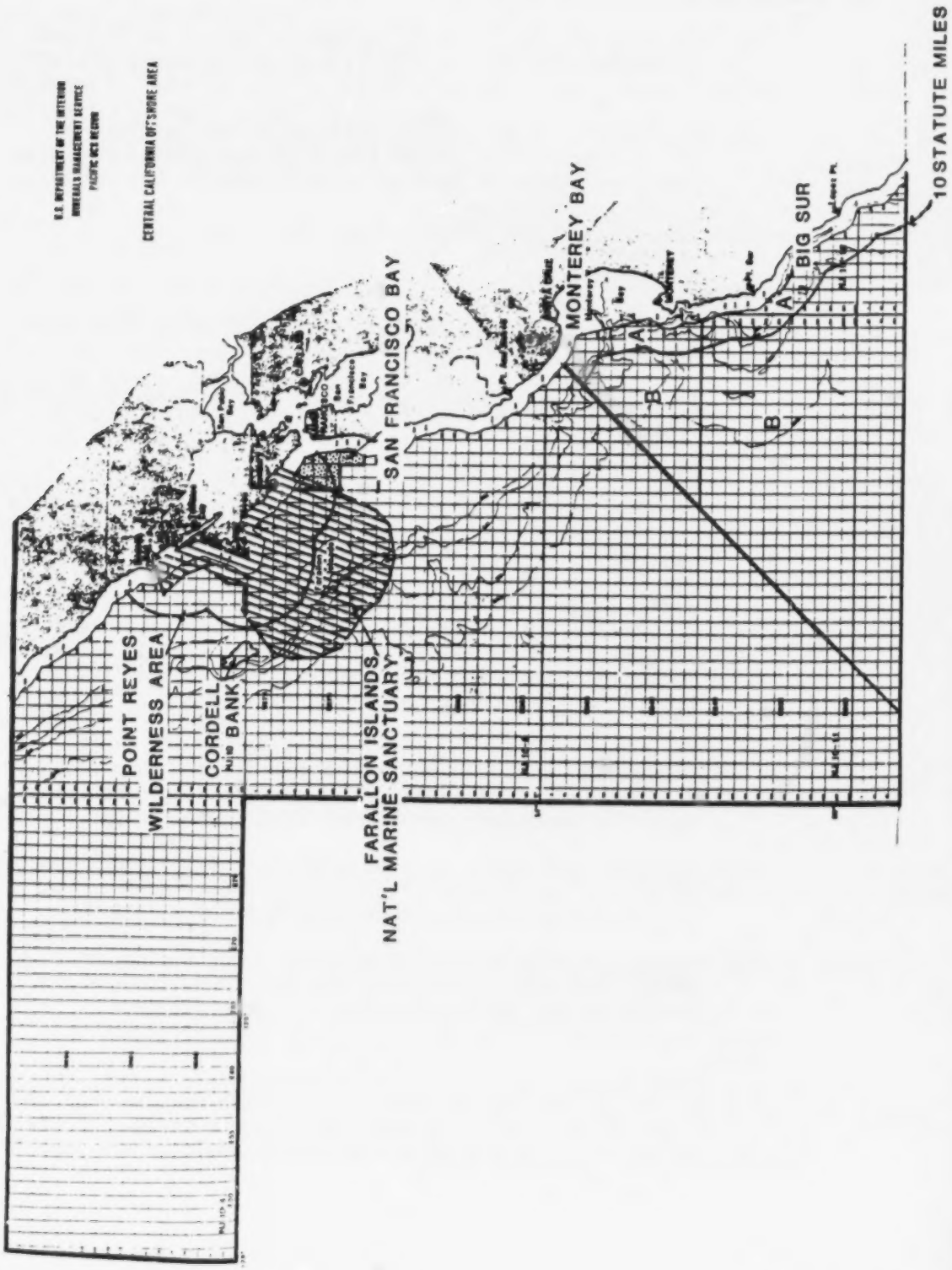
(h) Channel Islands National Marine Sanctuary - consists of about 175 blocks and was designated by a Notice published in the Federal Register by NOAA on March 30, 1981.

(II) Other

1-c-i-C Select a set of subareas for further analysis with the decision on deferral postponed until the Proposed Final Program stage. In the interim, the set of subarea deferral candidates would be analyzed further

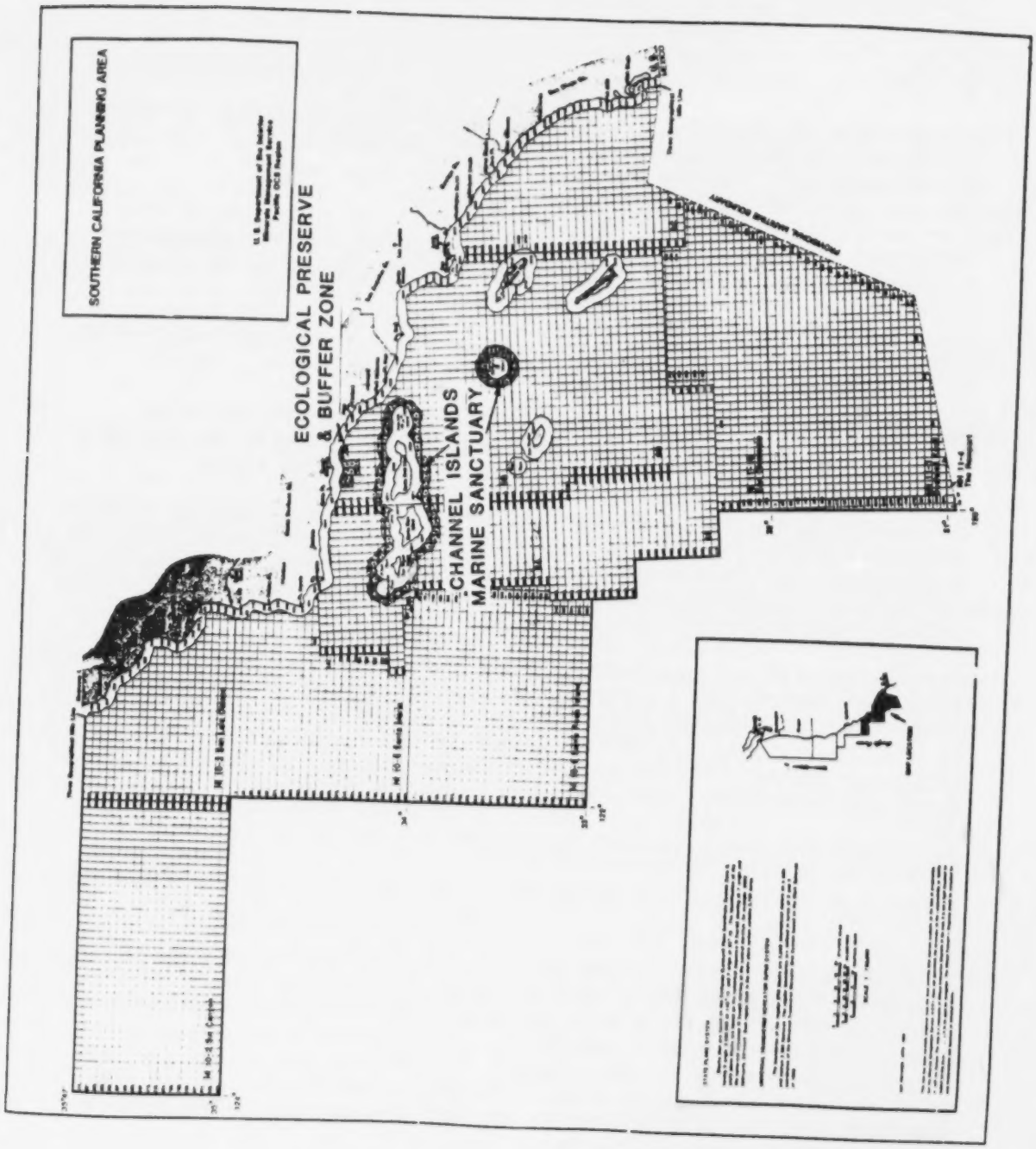
Map 3

Six of the Eight Areas Listed in Option 1.c.i.B.(I)



Map 4

Two of the Eight Areas Listed in Option 1.c.i.B.(I)



by MMS and would be submitted to the public for comments. Those subareas would then be considered for deferral as part of the decision on the Proposed Final Program.

1-c-i-D Defer all decisions on subarea deferrals to the Proposed Final Program

OPTION 1-c-ii Limit deferrals to the presale process, but "flag" subareas at the 5-year program stage for special attention during individual presale processes.

Specific subareas would be singled out in the Proposed Program for special attention (possible deferral, special lease stipulations, etc.) at Area Identification or possibly earlier at the Call stage of each sale. No section 18 comparative analysis would have to be prepared at the 5-year program stage.

"Flagging" subareas at the 5-year program stage has some of the advantages of deferrals (such as reducing some of the conflict concerning the program) while avoiding some of their disadvantages (such as the analytical problems of complying with section 18 requirements and eliminating areas before more becomes known about them during the presale process). Yet, "flagging" may be taken to prejudge the question of deferral at the presale stage.

OPTION 1-c-iii Limit subarea deferrals to the presale process without "flagging" subareas but describe the process for making subarea deferrals in the presale process at the 5-year program stage.

This option is similar to Option 1-c-ii, but no specific subareas would be singled out. The full list of deferrals recommended by commenters on the 5-year program could be cited as the type of candidates which would be considered for deferral, special stipulations, or other consideration at the Call and other presale steps.

The Area Identifications for Sale 111, Mid-Atlantic, and Sale 94, Eastern Gulf of Mexico, and the Calls for Sale 110, Central Gulf of Mexico, and Sale 97, Beaufort Sea, are examples of "focusing on promising acreage" as an alternative to both subarea deferrals and "flagging" at the 5-year program stage. Like the "flagging" option, this option could achieve a number of the objectives of deferrals without bearing the costs of premature deferrals.

Revising Planning Area Outer Boundaries

OPTION 1-d Revise the boundaries of the Northern California and Washington-Oregon planning areas to coincide with the limits of the EEZ.

This option could give exploration and geological and geophysical survey companies incentives to explore the deeper waters of the planning areas. If this option is selected, MMS will consult with the Department of State on the appropriate description of these boundaries. The EEZ line coincides with the Fisheries Conservation Zone Line and extends to approximately 129° W longitude at its furthest seaward point in these two planning areas. Washington and Oregon, on the other hand, commented that the present boundary at 128° extends too far seaward and is beyond the area of hydrocarbon potential.

2. Leasing Schedule Options for the Proposed Program

The location and timing of lease sales which comprise a 5-year OCS leasing program must be based on consideration of the factors specified in section 18(a)(2) and the balancing requirement of section 18(a)(3). The text of those sections appears in Part I, above. Part II and the supporting appendices provide the required analysis.

Section 18 Considerations

For those factors that were quantified, the resulting net social value estimates are shown in Table 12.1. As Table 12.1 shows, the social costs of OCS oil and gas activity make the net social value in each area somewhat lower than the net economic value, but do not change the ranking of the various areas by net economic value. These estimates, plus other quantitative and qualitative information and the economic guidelines set forth in Appendix F, provide a starting point for determining the location and timing of lease sales in each area (see Part II.D, above).

Once these guidelines have been reviewed, other considerations are also relevant to the scheduling of sales:

-Judgments about the degree of precision of and weight which should be attributed to estimates of relative net social value, based on such factors as

-- The sensitivity of net economic value estimates in the base case to changes in assumptions which correspond to the possibility of changes in the world oil market, including those that could result from an oil supply disruption. This consideration relates to the net social value quantitative balancing of costs and benefits pursuant to section 18(a)(3). The variation in starting oil prices (from $19 to $29 per barrel) and in real oil price growth rates (0 to 2 percent annually) results in a range depicted in Figure 1. Table 12.1 reflects only the variation in starting oil prices. Tables 9 and 13 in Appendix F reflect the variation of the real oil price growth rates and variation in discount rates (6 percent and 8 percent).

-- An evaluation of the available geological and geophysical data on which the resource estimates are based (see Appendix E). This consideration relates to section 18(a)(2)(A) both in itself and insofar as it contributes to net social value quantitative balancing of costs and benefits pursuant to section 18(a)(3).

-The history of leasing and exploration in an area (see Appendix H). This history is the source of the information which the Secretary is required to consider under section 18(a)(2)(A) and a necessary consideration for making a decision on a leasing program under section 18(a);

-The relative marine productivity/environmental sensitivity analysis considered in itself, as well as an input to the social cost analysis (see Part II.B.3 and Appendix I). This consideration is required by section 18(a)(2)(G).

-The desirability of acquiring new geological and geophysical data through exploratory work, including the drilling attendant on leasing. This consideration is specified as one of the purposes of the OCS Lands Act Amendments, which added section 18--see OCSLAA section 102(9)--and it relates to a crucial element in complying with the section 18(a) standard that the program meet national energy needs.

-The desirability of follow-up sales in areas with scheduled sales and/or existing leases. This consideration is based on the provision of section 18(a) that the leasing program be one which the Secretary determines will best meet national energy needs.

-The avoidance of drainage of unleased blocks. This consideration is based on the requirement of section 18(a)(4) that DOI obtain fair market value for lands leased and rights conveyed.

-Time necessary to acquire useful data from blocks leased in the preceding sale in an area. This consideration is related to the requirement that the leasing program meet national energy needs and the requirement of section 18(a)(4) that DOI obtain fair market value for lands leased and rights conveyed.

-Administrative considerations, including the cost of offering an area in a sale. If an area is being offered for the first time or after a long hiatus in leasing, the cost of holding a sale, including environmental studies, would be higher than in the case where funds have already been expended for studies and other presale analysis. The marginal cost of holding an additional sale in an area is estimated to be approximately $1 million. This consideration reflects the section 18(b) requirement that the Secretary include in the leasing program estimates of appropriations and staff for carrying it out. Section 18(b) makes clear the congressional view of the relevance of administrative resources and limitations to the formulation of a leasing program under section 18(a).

-Comments in response to Federal Register notices including comments of States and industry rankings of areas by resource potential and by exploration interest (see Tables 13.1, 13.2, and 13.3 on the following pages and Appendices B and D). Public comments are called for by sections 18(c) and (d). Industry comments are specifically called for by section 18(a)(2)(E).

A summary of comments on location and timing issues follows.

Location Comments

General: Alabama commented that more sales should be held outside the Gulf of Mexico to conduct a timely inventory of OCS oil and gas reserves. Louisiana and Texas commented that the proposed locations are inappropriate because they do not provide for equitable sharing of leasing among various regions. Chevron, Shell, Marathon, NOIA, Sohio, and Amoco stated general agreement with the location of proposed sales. Tenneco commented that renewed emphasis should be placed on offering leases in Alaska and California OCS regions, where the greatest potential for new resources exists. The Western Oil and Gas Association commented that because of unique and innovative exploration philosophies, high interest in an area on the part of a majority of industry members should not be

an absolute prerequisite for determining sale location. The API urged that the location characteristics of the present 5-year program be maintained in the next program. The NRDC suggested that lower resource estimates indicate that areas low in hydrocarbon potential and high in marine productivity and sensitivity should not be leased.

Alaska: The State of Alaska and NOAA stated support for the decision not to include the St. Matthew-Hall, Aleutian Basin, Aleutian Arc, and Bowers Basin planning areas in the schedule. Greenpeace opposed leasing in St. George Basin.

Atlantic: Massachusetts commented that the North Atlantic planning area is too environmentally sensitive and contains too little promising acreage to justify leasing. The Florida Public Interest Research Group stated that they do not object to the proposed location of sales. Maryland, New Hampshire, New Jersey, South Carolina, and Virginia stated their general agreement with the proposed locations.

California: The City of Eureka endorsed proposed leasing in the Northern California planning area.

On the other hand, several local governments (listed above), the Marin Conservation League and the California Public Interest Research Group noted the location of sales off California in resolutions stating general opposition to the Draft Proposed Program. Both the City and County of Santa Barbara opposed the draft proposed leasing schedule. The Association of Monterey Bay Area Governments and the Monterey Bay Unified Air Pollution Control District expressed opposition to leasing in the Central California planning area. The League for Coastal Protection commented that no leasing should take place in the Central and Northern California planning areas until studies are completed. The Environmental Coalition stated opposition to leasing off the entire west coast. Several citizens of California submitted comments, the great majority of which opposed the location of lease sales off California.

Gulf of Mexico: Alabama commented that the Draft Proposed Program made a reasonable proposal for leasing in the Central and Western Gulf of Mexico and that leasing in the Eastern Gulf of Mexico should be accelerated if there were a discovery there. Texas and Louisiana did not dispute the appropriateness of leasing in the Gulf of Mexico, but rather commented on the desirability of a balanced national program.

Washington-Oregon: Oregon gave qualified approval for including the Washington-Oregon planning area in the leasing schedule but requested that the planning area have a seaward boundary of 125° W longitude. Washington requested that lease offering be limited to promising geologic structures. Greenpeace commented that leasing should not be conducted in the Washington-Oregon planning area.

Timing Comments (where different from Location Comments)

General: The EPA recommended that the range of alternative leasing schedules proposed be widened to provide longer intervals between sales in certain areas where triennial sales are now proposed. Louisiana stated that holding annual sales in the Central and Western Gulf of Mexico OCS planning areas and triennial sales in other areas will result in increasing the rate of depletion of the

resources in the former areas and prolonging the life of those in the latter areas. Alaska, Connecticut, Delaware, Florida, Georgia, Maryland, New Hampshire, North Carolina, Rhode Island, South Carolina, Virginia, and Washington agreed with the proposed number of sales and interval between them.

ARCO and Texaco concurred with the proposed leasing schedule. The U.S. Chamber of Commerce and the Alaska Oil and Gas Association stated their general opposition to deceleration of the pace of leasing. Sohio and Tenneco stated their agreement with annual leasing in the Central and Western Gulf of Mexico planning areas and their opposition to slowing the pace elsewhere, particularly in the Eastern Gulf of Mexico planning area. They also raised the concern that the triennial leasing pace is not compatible with regulations requiring public release of well information 2 years after its date of submission. Union Texas Petroleum, Chevron, BP Alaska, Shell, NOIA, Exxon, Amoco, Western Oil and Gas Association, and API generally agreed with the annual pace of leasing in the Gulf of Mexico and stated their preference for biennial leasing in most other planning areas. Several of these companies made specific recommendations for scheduling in particular planning areas, and Exxon presented a complete alternative 5-year schedule. Fairfield Industries concurred with the annual pace of leasing in the Central and Western Gulf of Mexico planning areas, but suggested having 6 months' separation between Central and Western Gulf of Mexico sales, commencing in 1986 rather than 1987. Marathon endorsed annual leasing in the Central and Western Gulf of Mexico planning areas and stated support for triennial leasing elsewhere as long as acceleration will be possible under certain conditions.

The Massachusetts Audubon Society stated that the interval between sales always should be long enough to complete gathering and analysis of environmental information, noting that in some cases the process could exceed 3 years.

Alaska: NOAA stated support for triennial leasing in Alaska OCS planning areas and suggested that the 3-year interval between sales be increased in certain situations.

Atlantic: Maine commented that the proposed triennial pace in the Atlantic is appropriate, but requested more explanation of the schedule before actually endorsing the timing of sales in the North Atlantic planning area. Massachusetts stated that only one North Atlantic sale is warranted during the 1986-1991 period. New Jersey recommended deceleration of the sale schedule for both the Mid-Atlantic and North Atlantic planning areas. The County of Volusia (FL) stated that the schedule proposes too many sales during the 5-year program. The Florida Public Interest Research Group stated their agreement with triennial leasing off Florida.

California: The City of Los Angeles supported the triennial pacing proposed for the Southern California Planning Area, but noted that the interval between Sale 80 and proposed Sale 95 is 2½ years. The City of Pismo Beach recommended that the number of sales be reduced and the interval between them expanded. The County of Ventura commented that the triennial leasing schedule is welcome. The City of Santa Monica stated they are encouraged that the proposed schedule slows the pace of lease sales. Get Oil Out, Inc. stated that triennial leasing is a step in the right direction. Greenpeace cited triennial leasing as a general improvement, but stated that it does not change the situation of California as a whole.

Table 13.1

Industry Interest in OCS Planning Areas /1
Summer 1984

	Overall Ranking/2	Range of Companies' Rankings/3
1	Central Gulf of Mexico	1 to 5
2	Western Gulf of Mexico	1 to 7
3	Beaufort Sea	1 to 7
4	(tie) Southern California	1 to 11
4	(tie) Central & Northern California	3 to 14
6	Eastern Gulf of Mexico	3 to 12
7	Navarin Basin	2 to 11
8	North Aleutian Basin	3 to 14
9	St. George Basin	3 to 15
10	Chukchi Sea	2 to 13
11	North Atlantic	7 to 22
12	Norton Basin	8 to 18
13	Washington-Oregon	5 to 21
14	Mid-Atlantic	9 to 23
15	Hope Basin	10 to 19
16	Cook Inlet	9 to 20
17	Shumagin	12 to 22
18	South Atlantic	10 to 24
19	Gulf of Alaska	12 to 21
20	St. Matthew-Hall	14 to 23
21	Kodiak	13 to 24
22	Bowers Basin	16 to 24
23	(tie) Aleutian Arc	12 to 24
23	(tie) Aleutian Basin	15 to 23

/1 This table has been included for comparison with the current industry rankings in Table 13.2. Note however, that a one for one comparison is not possible since, among other things, the number and configuration of planning areas have changed, exploration results since Summer 1984 may have affected rankings, and future price expectations of individual companies may have changed. This table is based on responses from 18 companies, not all of which ranked all areas.

/2 Rank order of mean (average) ranks of companies ranking the OCS planning area on the basis of interest in exploration and development.

/3 Reflects highest and lowest ranking by companies ranking the particular OCS planning area on the basis of interest in exploration and development.

Table 13.2

Industry Interest in OCS Planning Areas
Spring 1985

	Overall Ranking/1	Range of Companies' Rankings/2
1	Central Gulf of Mexico	1 to 2
2	Western Gulf of Mexico	2 to 5
3	Beaufort Sea	1 to 6
4	Southern California	1 to 8
5	Eastern Gulf of Mexico	3 to 10
6	North Aleutian Basin	3 to 9
7	Central California	4 to 11
8	Navarin Basin	4 to 10
9	Northern California	4 to 11
10	Chukchi Sea	4 to 20
11	St. George Basin	8 to 17
12	Norton Basin	9 to 18
13	Hope Basin	9 to 19
14	North Atlantic	12 to 17
15	Mid-Atlantic	11 to 21
16	Cook Inlet	10 to 21
17	South Atlantic	12 to 22
18	Washington-Oregon	11 to 22
19	Straits of Florida	14 to 24
20	Gulf of Alaska	15 to 22
21	Shumagin	14 to 25
22	Kodiak	18 to 25
23	St. Matthew-Hall	16 to 26
24	Aleutian Basin	14 to 25
25	Bowers Basin	21 to 26
26	Aleutian Arc	20 to 26

/1 Rank order of mean (average) ranks of companies ranking the OCS planning area on the basis of interest in exploration and development.

/2 Reflects highest and lowest ranking by companies ranking the particular OCS planning area on the basis of interest in exploration and development.

Table 13.2 includes rankings of the nine responding companies, three of which gave partial rankings. This relatively small number limits the usefulness of Table 13.2 as an indicator of the collective interest of all potential producers. Nonetheless, there is a considerable degree of parallelism between industry rankings in Summer 1984 (Table 13.1) and Spring 1985 (Table 13.2).

Table 13.3

Comparison of Net Social Value and Industry Interest Rankings for the Proposed 5-Year Program

Planning Area	Net Social Value	Industry Interest (Spring 1985)
Central Gulf of Mexico	1	1
Western Gulf of Mexico	2	2
Southern California	3	4
South Atlantic	4	17
Central California	5	7
Northern California	6	9
Eastern Gulf of Mexico	7	5
Navarin Basin	8	8
Mid-Atlantic	9	15
Washington-Oregon	10	18
Beaufort Sea	11	3
St. George Basin	12	11
North Atlantic	13	14
Straits of Florida	14	19
Chukchi Sea	15	10
Gulf of Alaska	16	20
North Aleutian Basin	17	6
Norton Basin	18	12
Kodiak	19	22
Hope Basin	20	13
Shumagin	21	21
Cook Inlet	22	16

On the other hand, the County of San Luis Obispo recommended a minimum of 12 months between sales off California and 3 years between sales in frontier areas. The San Diego Association of Governments and the City of San Diego called for no more than one sale every 5 years. The San Francisco Bay Sierra Club Chapter, League of Women Voters of San Luis Obispo County, Environmental Center of San Luis Obispo County, and Whale Center commented that the proposed scheduling would not slow the pace of leasing off California as a whole, since there would be one sale off California per year. Friends of the Sea Otter commented that leasing would be accelerated under the proposed schedule. The Santa Lucia Sierra Club chapter stated that lease sales should be held every 5 years.

Washington-Oregon: Oregon stated that the time proposed for conducting environmental studies prior to a sale in the Washington-Oregon planning area is inadequate.

Gulf of Mexico: Texas commented that the proposed schedule very nearly approximates the current rate of lease sales being held. Greenpeace also commented that annual leasing in the Central and Western Gulf of Mexico planning areas forces those areas to assume a disproportionate amount of environmental and economic costs of development. The Sierra Club Lone Star Chapter (Galveston, Texas) commented that biennial sales in all of the Gulf of Mexico would be sufficient.

Scheduling Sales in High Net Social Value Areas

As can be seen from Table 12.1, the Central and Western Gulf of Mexico areas are clearly the high net social value areas. Each of them has over three times the potential net social value of the next best areas--over the full range of alternate price assumptions. Industry has also ranked these two areas most highly. It may thus be appropriate to hold annual lease sales in the Central and Western Gulf of Mexico, continuing the same timing in those areas as in the 1982 5-year leasing program.

Drainage and field development considerations also figure strongly in the timing of lease sales in the Central and Western Gulf of Mexico. The MMS estimates that because of the level of activity in the Central and Western Gulf of Mexico, there will be about 100 drainage and development blocks in each of those two areas each year. Failure to lease these blocks once drainage begins reduces Federal revenues and could provide unwarranted profits to adjacent leaseholders. Failure to offer development blocks subsequent to nearby discoveries can lead to production delays or less than optimal field development.

Scheduling Sales in Intermediate Net Social Value Areas

The Intermediate net social value group of planning areas (see Part II.D) contains all other planning areas which have a net social value estimate exceeding $0.5 million ($1987) for at lease one of the oil price assumptions: Southern California; Eastern Gulf of Mexico; Navarin Basin; Central California; Northern California; South Atlantic; Beaufort Sea; Chukchi Sea; Mid-Atlantic; St. George Basin; Washington-Oregon; North Atlantic; Norton Basin; North Aleutian Basin; and Gulf of Alaska. Considerable discretion within section 18 requirements is appropriate in scheduling sales in these areas. It would be reasonable to

schedule sales in the intermediate areas in a variety of ways, including biennially or triennially, based a consideration of net social value, industry interest, and other section 18 factors. Further distinctions with respect to scheduling sales in the intermediate group could be made by means of the frontier exploration sale request for interest process.

In interpreting MMS net social value estimates for the purpose of formulating a 5-year leasing program, it should be noted that section 18(a)(2)(E) specifically requires consideration of the interest of potential producers of oil and gas. Of particular significance are those cases in which industry ranks an area differently from MMS (see Tables 13.1 and 13.2 and Appendices B, D, and F). For example, industry ranked the Beaufort Sea in the top three of all areas, whereas MMS resource estimates show Beaufort Sea (not counting estimated gas resources) in the middle rank of all areas. Another example is the South Atlantic, which MMS ranked high whereas industry ranked it low.

There are a number of factors which can cause industry interest rankings to differ from MMS net social value rankings. The MMS net social value ranking is computed from the risked mean resource estimate. Industry commenters may have different estimates of risk or may weigh conditional (unrisked) estimates more highly. Industry interest rankings may also include considerations not reflected in MMS resource estimates, such as existing infrastructure and ease of operations. Finally, some companies may include in their ranking perceptions of potential legal and regulatory hurdles which are not accounted for in net social value rankings.

The Eastern Gulf of Mexico has more resource potential in the high value category than Navarin Basin and about twice the per barrel cost of delay (see Appendix F, Tables 7 and 9). This would suggest that, in general, leasing in the Eastern Gulf of Mexico should have priority over leasing in the Navarin Basin. However, the substantial gain in resource potential at higher prices in the Navarin Basin area contributes to making it reasonable to schedule lease sales there more frequently than in other areas which do not show such substantial gains (see Appendix F, Table 8).

Several areas show substantial gains in resource potential if starting oil prices are higher: Central California; Northern California; Navarin Basin; Eastern Gulf of Mexico; Beaufort Sea; Mid-Atlantic; and St. George Basin (see Table 2). It may thus be reasonable to schedule sales in each of these areas during the 1987-1991 period and to consider additional sales in areas most likely to gain from price increases, new technology, or new data from exploration.

Especially in the case of areas that have not yet been offered for lease, the MMS resource estimating process is limited by the paucity of available drilling data. More data may well lead to a significant revision of resource estimates.

Four areas have never had a lease sale actually held: Chukchi Sea, Hope Basin, Shumagin, and Kodiak. Three other areas have not had a lease sale for twenty or more years: Northern California, Central California, and Washington-Oregon.

It is worth recalling at this point that the net social value figures are planning area estimates and do not reflect the geographic distribution of prospects within a planning area. It is during the presale process that that question is addressed. During the presale process, the balancing of resource, environmental, and multiple-use considerations is performed. For example, in the presale process for Sale 92, North Aleutian Basin, a relatively small part of the planning area has been rated as highly prospective by industry. The presale process for Sale 92 reduced the size of that sale to about 17 percent of the planning area.

Scheduling Sales in Low Net Social Value Areas

The Low net social value group of planning areas (see Part II.D) includes areas estimated to have negligible leasable resources and thus negligible net economic value. Some of the areas in this group are estimated to have resources which are developable (i.e., profitable to develop once found) but not leasable (i.e., not profitable for a firm to bid on, given risk and exploration costs) (see Table 4).

The balancing of benefits and costs for areas with no "leasable" resources must proceed on a per-barrel basis rather than on total planning area estimates. The comparison can proceed by making the assumption--not made by the net economic value analysis whose results are displayed in Tables 1, 2, and 12.1 in the SID--that if some or all of the "developable" resources in these areas were leased, their expected private value (the after-tax net present value for the bidder--see Appendix F) would have to be equal to or greater than zero. Assuming--on the low side--that private value is equal to zero for each of those planning areas, and assuming a $24/bbl starting oil price, it is possible to compute the estimates of net economic value per barrel for those areas (see Table 12.2, above). In all of these areas, the net economic value projection exceeds the social cost projection.

As indicated in Part II.B and Appendix F, one consideration involves the possible increases in leasable resource potential and net economic value that could result from increases in oil prices, new geologic and geophysical data, or other factors affecting costs and risk. One such factor which could change the attractiveness of low-valued Alaska areas would be the lifting of the legal prohibition on the export of oil to Japan. The reduced costs of transporting certain Alaskan oil to Japan could cause the net social value of Alaska OCS oil and gas to rise.

An evaluation of the available geophysical and geological data on which MMS resource estimates are based appears in Table 12.1 and Appendix E. The limitations of the available data as well as the specific mandate of section 18(a)(2)(E) call for recourse to the judgment of potential oil and gas producers as expressed in comments as an important source of additional information (see Tables 13.1 and 13.2 and Appendices B and D). This is particularly so since potential bidders are under no constraints to submit bids and that the planning of leasing activity, therefore, must give considerable weight to expressions of industry interest in order to avoid wasting the planning resources of all parties.

Providing Incentive for the Collection of More Geological Data

In addition to MMS and industry rankings, another consideration with respect to scheduling a sale in an area in the Low net social value group is that it could create an incentive for firms to collect additional data. That consideration is a salient one for areas where there is a paucity of geological and geophysical data (see Appendix E). If additional data resulted in changes in current interpretations of the hydrocarbon potential of an area, leasing there could be pursued; if not, leasing there could be deferred. Section 102(9) of the OCS Lands Act Amendments of 1978 provides a mandate for the early assessment of the oil and gas resources of the OCS.

Effects of Deferring Leasing in a Planning Area

It should be noted that the deferral of an area from inclusion in the leasing program means that, barring a significant revision of the new program, it will not be offered for lease through 1991. As a result, the incentive to gather new geological and geophysical data on such an area could be reduced, so that the data available for deciding whether to include that area in the formulation of future programs could be no better than at present.

It is important to stress that the deferral of leasing in any planning area in the program for 1987 through 1991 in no way affects any United States claims to jurisdiction and control over submerged lands under the OCS Lands Act or the EEZ Proclamation of 1983. Changes in MMS's resource estimates, economic conditions, and/or industry interest may lead, under future 5-year programs, to the offering of blocks located in any planning area not included in the 5-year program for 1987 through 1991. All maps of the new program will continue to show all OCS planning areas, whether leasing is scheduled there in the new program or not.

The schedule options presented here specify only the year in which a sale would be held. Considerations regarding the timing of sales within the year and the timing and description of presale steps are set forth in Appendix L. It should be noted that the number of sales in an area in the new program is not an independent element. Rather, a "triennial" sale, as such, is scheduled for the third calendar year after the last scheduled sale in the area. Because of administrative considerations, for example, balancing workload at the regional and headquarters offices, the interval between triennial sales may be somewhat more or less than 36 months. A schedule showing the option selected and presale steps by month will be issued as part of the Federal Register Notice which will announce the Proposed Program.

Decision Options for the Proposed Program

OPTION 2-a - The Base Schedule of Standard Sales

The revised base schedule adjusts the comparable option selected for the Draft Proposed Program for the new timeframe January 1987 - December 1991 and extends the frequency selected for the new program to the added half-year. The revised base schedule contains 32 sales over 5 years in 17 planning areas. It schedules annual sales in the two areas in the High net social value group (the Central and Western Gulf of Mexico) and triennial sales in 14 other areas in the Intermediate

net social value group (see Part II.D). It schedules sales in all Intermediate net social value group areas, except for the Gulf of Alaska and the Straits of Florida. It defers leasing in the Gulf of Alaska corresponding to the Secretary's February 1985 decision to place Sale 88, Gulf of Alaska/Cook Inlet, on hold. Scheduling a sale in the Straits of Florida is discussed in option 2-b.

The first OCS sale offshore Washington and Oregon since 1964 would be scheduled, given that area's net social value ranking and industry interest. The sale for this area is scheduled late in the 5-year period in order to allow time for the necessary environmental studies to be performed. The time allotted for studies exceeds that required by section 20 of the OCS Lands Act and regulations at 30 CFR 256.82(c), which provide that a study for an area be commenced at least 6 months prior to holding a lease sale for that area.

A single standard sale is scheduled in Shumagin--Sale 86, which is carried over from the current schedule. Industry responses to the Federal Register Notice of October 15, 1984 (49 FR 40228), support the scheduling of an initial Shumagin sale. Shumagin is the only Low group area included in Option 2-a. It should be noted that the quantity and quality of geological and geophysical data for Shumagin are rated Very Poor by MMS (see Appendix E). A second Shumagin sale would be part of Option 2-f. The base schedule defers leasing in all areas in the Low net social value group other than Shumagin, i.e., Kodiak, Cook Inlet, and Hope Basin.

-The Base Schedule Decision Option

OPTION 2-a - Adopt the base schedule of 32 standard sales proposed in the Draft Proposed Program, revised to begin in January 1987 (see Table 14).

OPTION 2-b - Add a single sale in the Straits of Florida in 1991.

As part of the decision on the Draft Proposed Program, the area south of approximately 28° N. latitude was made the new Straits of Florida planning area. No decision on scheduling a sale in that area could be made until the section 18 analysis and consultation requirements had been met for that area.

The net social value range for the Straits of Florida is $14-33 million ($1987) over the $19-29 per barrel variation of alternative price assumptions. This area is ranked 14th out of 22 planning areas shown on Table 12.1. Comments on leasing in this planning area were negative from most parties. Industry ranked the Straits of Florida as 19th out of 26 planning areas in response to the March 1985 request for comments on the Draft Proposed Program.

This decision option provides for adding a single sale in the Straits of Florida in 1991, so that the necessary environmental studies could be performed if this option is chosen.

OPTION 2-c - Defer leasing in any or all of six planning areas.

This option would defer from leasing up to six whole planning areas scheduled for leasing in the Draft Proposed Program which were requested for deferral by various comments on the Draft Proposed Program: North Atlantic; Southern California; Central California; Northern California; Washington-Oregon; and North Aleutian Basin. This option provides for an exception to the scheduling formula for the base schedule on the basis of section 18(c) and 18(f)(1) comments cited above.

Table 14

Current Leasing Schedule Overlap With Option 2-a for the Proposed Program
(Base Schedule of Standard Sales)*

	1983	1984	1985	1986	1987	1988	1989	1990	1991	No. of Sales
ATLANTIC										4
North		82				96			S	
Mid-	76			111			S			
South	78			90			108			
GULF OF MEXICO										12
Western	74	84	102	105	S	S	S	S	S	
Central	72	81	98	104	110	S	S	S	S	
Eastern	69(II)	79	94			S			S	
PACIFIC										6
Southern CA		80			95			S		
Central CA	73						S			
Northern CA						91			S	
Washington-Oregon									S	
ALASKA										10
Beaufort Sea		87			97			S		
Chukchi Sea					109			S		
Norton Basin	57			100			S			
Navarin Basin		83			107			S		
St. George Basin	70			89			101			
N. Aleutian Basin				92			S			
Shumagin						86				
									Total	32

Sales to the left of the vertical line are in the current 5-year leasing schedule.
Sales to the right of the vertical line are a part of this option for the Proposed Program.

S = Sale not yet numbered. Sale numbers are those in the 1982 program.

*This table has been prepared based on the latest available scheduling information. Administrative considerations may delay the holding of a number of sales--Sales 111, 90, 97, 107, 109, 86, 101, and possibly others. If such a change occurs, the leasing schedule would be implemented so as to factor in that change, consistent with the scheduling policy selected by the Secretary. This also applies to the following two schedule tables.

Some of the decision considerations applicable to this option discussed with respect to subarea deferrals, above also apply to the deferral of whole planning areas. On one hand, removing high conflict areas at the earliest stage of the leasing process could reduce controversy and litigation over them. In addition, deferrals of portions of planning areas could reduce the analysis burden in the presale process for all parties.

On the other hand, deferrals may be premature and may limit flexibility if made before the availablility of the geological, geophysical, and environmental information usually gathered during the presale process for a sale. In addition, deferrals made at the 5-year program stage cannot be reconsidered for leasing for 5 years (unless a new 5-year program is developed--a 2-year process). This could have a dampening effect on information-gathering concerning areas which are deferred. Thus, deferrals may, effectively, become permanent.

OPTION 2-d - Adopt biennial sales in any or all of eight areas with higher value and/or higher interest.

This option provides for scheduling biennial sales in up to eight planning areas. This option schedules up to 39 sales in the same 17 planning areas included in Option 2-a. It differs from Option 2-a by amending it to schedule biennial sales in up to eight areas with higher value and/or higher interest: Southern California; Eastern Gulf of Mexico; Central California; Northern California; Navarin basin; Beaufort Sea; North Aleutian Basin; and St. George Basin. These areas are relatively highly ranked by MMS in terms of net social value (see Table 12.1) and/or by industry (see Tables 13.1 and 13.2). Indeed, these eight areas were ranked highest--after the Central and Western Gulf of Mexico--in industry interest as expressed in Summer 1984 and confirmed in Spring 1985. This option adds the North Aleutian Basin and St. George Basin to the six areas proposed for biennial sales in the Draft Proposed Program, paralleling the list of areas proposed for possible acceleration.

The benefits of offering these sales biennially instead of triennially is indicated in the cost of delay table (see Table 6) and in the section on the valuation of schedule alternatives.

The selection of this option would increase the workload of MMS. If this option is selected, its implications regarding necessary staff and appropriations will be addressed in the materials prepared in compliance with section 18(b).

Table 15 displays all sales which could be chosen in Option 2-d. It should be noted that the 26 month planning horizon for Alaska sales (from Call to sale) means that some sales accelerated by Option 2-d may appear to be separated by three years on Table 15 (e.g., Navarin Basin) when actually the timing would be approximately biennial.

OPTION 2-e - Designate Frontier Exploration Sales

The Draft Proposed Program scheduled 5 frontier exploration sales in Alaska areas so as to increase the flexibility of the schedule to respond to changes in economic conditions or new geologic and geophysical data. Those five areas are the Gulf of Alaska, Cook Inlet, Hope Basin, Kodiak, and Shumagin (1990). A frontier exploration sale is one for which industry interest is re-examined before the start of the presale process by means of a Request for Interest published in the Federal Register several months prior to the Call and/or the

Table 15

Current Leasing Schedule Overlap with Option 2-d for the Proposed Program
(Biennial Sales in up to 8 areas)*

	1983	1984	1985	1986	1987	1988	1989	1990	1991	No. of Sales
ATLANTIC										4
North		82				96			S	
Mid-	76			111			S			
South	78			90			108			
GULF OF MEXICO										13
Western	74	84	102	105	S	S	S	S	S	
Central	72	81	98	104	110	S	S	S	S	
Eastern	69(II)	79	94		S		S		S	
PACIFIC										8
Southern CA		80			95		S		S	
Central CA	73					S		S		
Northern CA						91		S		
Washington-Oregon									S	
ALASKA										14
Beaufort Sea		87			97		S		S	
Chukchi Sea					109			S		
Norton Basin	57			100			S			
Navarin Basin		83			107		S		S	
St. George Basin	70			89		101			S*	
N. Aleutian Basin				92		S		S		
Shumagin						86				
Gulf of Alaska			88							
									Total	39

Sales to the left of the vertical line are in the current 5-year leasing schedule. Sales to the right of the vertical line are part of this option for the Proposed Program.

S = Sale not yet numbered. Sale numbers are those in the 1982 program.

*The 26-month presale process for Alaska OCS sales results in the appearance that some of the areas proposed for biennial leasing have triennial leasing. A monthly schedule would show that the following 8 areas are proposed in this option for leasing as near to biennial as possible: Southern, Central, and Northen California; Eastern Gulf of Mexico; Beaufort Sea; Navarin Basin; St. George Basin; and North Aleutian Basin.

annual review of the program under section 18(e). If interest is insufficient to justify proceeding with the sale, it can be delayed. A Request for Interest can then be reissued on a perennial or less frequent basis until interest is determined to be sufficient to hold a sale or the sale is cancelled.

This approach is designed to add flexibility to the program by providing for the reasonable possibility that changes in geologic data and economic or other conditions could create bidding interest in the future in areas which now appear unattractive. For example, a substantial oil price increase (such as might result from an oil supply disruption), if anticipated to be relatively long-term, could make an area now unattractive to potential bidders into one which could be of interest to them. Other information of interest would included new geophysical data; new drilling data; new interpretations of existing data; and new estimates of costs of production. By requesting information and acting on it prior to the issuance of the Call, the risk of inappropriate expenditures for such sales would be minimized. One possible drawback of frontier exploration sales, however, is that the additional uncertainty as to whether they will be held might lead firms to avoid investing in data collection for them.

These sales would be in frontier areas where the assessment of potential oil and gas resources based on exploration results is very inconclusive (see Appendix E). Ensuring the early assessment of OCS oil and gas resources is one of the purposes of the OCS Lands Act Amendments (section 102(9)). In addition, a price increase which could result from an oil supply disruption could make frontier areas more attractive to industry (see Table 4). Finally, the scheduling of frontier sales has been interpreted by the court to have beneficial effects concerning the equitable sharing requirement of section 18(a)(2)(B) (see Part II.C).

-Comments on Frontier Exploration Sales

NOAA suggested that a supplemental studies program be established for planning areas in which frontier exploration sales are proposed.

Maine expressed agreement with the concept of frontier exploration sales with a request for interest step and urged that the concept be applied to the North Atlantic planning area. New Jersey stated that they have no opposition to frontier exploration sales, but stated that the process for such sales must include consultation with the Governors of affected States. Alaska commented not on the concept of frontier exploration sales but on one of the areas proposed for one, Hope Basin, to the effect that it would be beneficial to coordinate with the State of Alaska, which is planning an offshore sale adjacent to that area shortly before the Federal OCS sale.

The Western Oil and Gas Association stated agreement with the proposal to include frontier exploration sales. Exxon commented that only tentative sales should be planned for low interest areas and that industry interest in each proposed frontier exploration sale should be established during annual review of the 5-year program, rather than adding the request for interest presale step. The American Petroleum Institute expressed support for the inclusion of frontier exploration sales, but commented that the sales should be considered "standard" instead of "tentative".

-Frontier Exploration Sale Decision Options (see Table 16)

OPTION 2-e Designate frontier exploration sales as follows:

OPTION 2-e-i - Confirm any or all of the areas designated in the Draft Proposed Program for frontier exploration sales in the Gulf of Alaska, Cook Inlet, Hope Basin, Kodiak, and Shumagin (1991).

OPTION 2-e-ii - Add frontier exploration sale designation to all sales in any or all of the following areas: North Atlantic; Mid-Atlantic; South Atlantic; and/or Washington-Oregon. This option extends the frontier exploration sale category to include other areas of low estimated resources, net social value, and/or industry interest.

OPTION 2-f - Supplemental Sales

This option would add an annual sale to offer a small number of selected blocks in areas other than the Central and Western Gulf of Mexico: drainage and development blocks; and blocks on which bids were rejected in the preceding year. This option is the same as the one proposed in the Draft Proposed Program.

-Rejected Bid Blocks

The small annual reoffering of blocks which received bids which were rejected in sales held in the prior calendar year in these areas would diminish any delay cost associated with offering the blocks 2, 3, or more years in the future. It would also provide for the timely offering of blocks based on evolving geological and geophysical information and would assure receipt of a fair return to the public for blocks on which the Government possesses the latest data. In 1984, there were nine such rejected bid blocks.

-Drainage and Development Blocks

This option would reintroduce the concept of drainage sales on a basis compatible with the requirements of section 18. (Twelve drainage sales were held in the Gulf of Mexico between 1959 and 1978.) A precedent for this provision exists in Alaska Statutes 38.05.180(d)(1) and (2), which allows the Commissioner of the Alaska Department of Natural Resources to issue leases in an area not included in a State 5-year leasing program if (1) the land to be leased was previously subject to a valid State or Federal oil and gas lease, or (2) the land is contiguous to land under State, Federal, or private leases and the Commissioner makes a written finding, after hearing, that leasing of the land would result in a substantial probability of early evaluation and development of the land to be leased.

A drainage tract is one which has a nearby well on a lease which is capable of producing oil or gas, and the tract could suffer drainage if and when such a well is placed on production. The reservoir is interpreted to extend under the drainage tract to some extent. A development tract is one which has nearby wells on a lease with indicated hydrocarbons and which is not indicated to have a productive reservoir extending under the tract. There should be some indication that some part of the tract is on the same general structure as the proven productive well or wells.

The expeditious identification and offering of drainage blocks would minimize potential losses in their sale value because as drainage continues, the net present value of the block being drained diminishes. In areas other than the

Table 16

Current Leasing Schedule Overlap with Options 2-a and 2-e or the Proposed Program
(Base Schedule + up to 10 Frontier Exploration Sales)

	1983	1984	1985	1986	1987	1988	1989	1990	1991	No. of Sales
ATLANTIC										
North		82				96[S+]			S+	
Mid-	76			111			S+			
South	78			90			108[S+]			
GULF OF MEXICO										
Western	74	84	102	105	S	S	S	S	S	
Central	72	81	98	104	110	S	S	S	S	
Eastern	69(II)	79	94			S			S	
PACIFIC										
Southern CA		80			95			S		
Central CA	73						S			
Northern CA						91			S	
Washington-Oregon									S+	
ALASKA										
Beaufort Sea		87			97			S		
Chukchi Sea					109			S		
Norton Basin	57			100			S			
Navarin Basin		83			107			S		
St. George Basin	70			89			101			
N. Aleutian Basin				92			S			
Shumagin						86			S+	
Kodiak									S+	
Cook Inlet									S+	
Gulf of Alaska						S+				
Hope Basin									S+	
										Total

Sales to the left of the vertical line are in the current 5-year leasing schedule. Sales to the right of the vertical line are part of this option for the Proposed Program.

S = Sale not yet numbered. Sale numbers are those in the 1982 program.
S+ = Frontier Exploration Sale.

offering of drainage and development blocks), the time intervals between sales could result in substantial losses in bonuses to the Government on blocks identified as drainage and development blocks. Also, failure to offer drainage and development blocks expeditiously could adversely affect the efficient production of the prospect's resources.

Since the largest structure on the OCS covers only approximately 35 blocks, even if an entire structure were offered the number of drainage and development tracts offered would likely be very small compared to the size of a standard sale.

-Compliance with the National Environmental Policy Act (NEPA)

To comply with NEPA, an environmental assessment (EA) would be written on these drainage, development, and rejected blocks sales. If each of the tracts had been covered in an EIS within the last several years, the preparation of an EA regarding the leasing of these tracts could well be sufficient to comply with the requirements of NEPA. However, it may be necessary to prepare a new EIS or a supplemental EIS if the EA finds that significant additional environmental information has become available, or environmental impacts are identified which were not evaluated in a recent EIS.

-Comments on Supplemental Sales

The EPA recommended timely communication on supplemental sales to allow adequate response to national pollutant discharge elimination system (NPDES) permit requests.

Maine stated that the supplemental sale concept is reasonable. Massachusetts commented that the provisions pertaining to supplemental sales are vague and may be inconsistent with the OCS Lands Act. New Jersey stated that adequate consultation with affected States must be a part of the supplemental sale process. North Carolina questioned the statutory authority for supplemental sales and offered the following three suggestions: 1) no block should be offered unless it has gone through an EIS process within the last five years; 2) consideration should be given to the need for a request for interest step in the prelease process; 3) guidelines and regulations should be developed before actually holding any supplemental sales.

The Senate Rules Committee of the California Legislature commented that California faces the likelihood of supplemental sales, and the overall pace of leasing is not slowed if such sales are included in the schedule. The California Department of Justice commented that addition of supplemental sales contributes to ambiguity regarding the timing of sales off California, thereby limiting effective notice as to when and where leasing and development will occur.

The City of Santa Barbara commented that supplemental sales will contribute to an annual leasing pace. The City of Pismo Beach and the county of San Luis Obispo noted supplemental sales in resolutions stating general opposition to the Draft Proposed Program.

Texaco, NOIA, the Alaska Oil and Gas Association, the Western Oil and Gas Association, and the API endorsed the concept of supplemental sales. Shell commented that the provision for supplemental sales should be retained, but it would be an inadequate response mechanism if major discoveries are made. Exxon commented that supplemental sales would be more useful if broadened in scope. Amoco expressed a need for more information describing the supplemental sale provision.

The League of Women Voters of San Luis Obispo commented that supplemental sales could speed up the leasing schedule. The League of Women Voters of Santa Barbara requested that no leases in the Santa Barbara channel or the Santa Maria Basin be offered in supplemental sales. The Natural Resources Defense Council commented that supplemental sales would disrupt the schedule and limit its value as a planning document.

A letter signed by Congressmen Mel Levine, Bill Lowry, and Leon R. Panetta commented that the proposed supplemental sales provision may conflict with the Secretary's stated commitment to a slower leasing pace, orderly consultations, and early conflict resolution.

OPTION 2-g - The Acceleration Provision

The DOI must plan for an unknown future with limited information. Changes in the world energy market as well as exploration results in frontier areas can dramatically affect the demand for offshore leases. The statutory requirement to develop a schedule which will best meet energy needs must be applied with due recognition that what will be known tomorrow may well be very different from what is known today. Thus, the 5-year program needs to have flexibility to adjust to major unforeseen developments.

One means of providing such flexibility is the following provision to permit the acceleration of leasing from triennial to biennial if the following carefully defined criteria are met. The Draft Proposed Program contained a proposal that the acceleration of sales be considered for any of the following eight areas (the same areas listed in the biennial sale option for the Proposed Program): Southern, Central, and Northern California; Eastern Gulf of Mexico; Beaufort Sea; Navarin Basin; North Aleutian Basin; and St. George Basin. Under this provision, however, the total number of sales in a planning area or in the program would not be increased.

-Statutory Authority

Two provisions of the statute which appear to be most applicable to the acceleration proposal are sections 18(a) and 18(e). Section 18(a) provides that:

> . . . The leasing program shall consist of a schedule of proposed lease sales indicating, as precisely as possible, the size, timing, and location of leasing activity which he [the Secretary] determines will best meet national energy needs for the five-year period following its approval or reapproval . . . .

The acceleration provision complies with section 18(a) in that the high degree of uncertainty about future hydrocarbon supplies and prices and about the location of future discoveries make such flexibility necessary in order to meet national energy needs.

Section 18(e) provides that:

> The Secretary shall review the leasing program approved under this section at least once a year. He may revise and reapprove such program, at any time, and such revision and reapproval, except in the case of a revision which is not significant, shall be in the same manner as originally developed.

Thus, the Secretary could, "at any time," review the leasing program and make a revision of it. The purpose of including the acceleration provision as part of an approved leasing program is so that its exercise would be the implementation of part of the approved program rather than a significant revision of it.

The DOI has numerous times exercised the authority to decelerate leasing in an area and that procedure would remain unchanged.

-Criteria for Implementation

In the Federal Register Notice of March 22, 1985, announcing the Draft Proposed Program, it was explained that the acceleration provision

> ... would be used only if warranted by changes in economic conditions (for example, substantially higher oil price expectations such as might result from a serious oil supply disruption) or geologic data (such as could come from major new discoveries). The question of whether to accelerate a sale in an area would be made on a sale-by-sale basis, as part of the required annual review of the program under section 18(e). No new sales would be added to the program in any planning area under this provision.

Further specification of the trigger for the acceleration provision is appropriate for the Proposed Program. The Proposed Program could either: specify a particular trigger or multiple triggers; or request comments on a particular trigger or multiple triggers.

Potential Triggers

GEOLOGIC TRIGGER: A major new discovery in an area makes more salient the cost of delay of leasing. The implementing procedure would be the issuance of a finding by the Secretary that a new discovery in a planning area indicates that biennial leasing there is in the national interest. This determination would be based on considerations of avoiding costs related to drainage and delays in exploration and production.

It is possible that in the planning areas subject to this provision a discovery could be made that would be commercial if a regional transportation infrastructure existed, however, the discovery would be of insufficient size to support the construction of such a system. If surrounding unleased wildcat acreage and other unleased areas previously thought to be nonprospective and/or high risk (either geologic or economic) would benefit from this additional information so that they would become of leasing interest, exploration could be accelerated--leading to additional earlier discoveries and production than might otherwise occur.

The provision for supplemental sales (Option 2-f) applies only to the areas nearby the discovery, and is thus not a substitute for this form of acceleration.

ECONOMIC TRIGGERS: The choice of an economic trigger is more complicated and it could be useful to receive public comments on a variety of economic triggers before making a proposal. Potential economic triggers could include events or criteria, and the criteria could be retrospective or prospective.

-Event Triggers

Event triggers could be keyed to the activation of established oil emergency response systems, such as the International Energy Agency's oil sharing agreement and the drawdown of the U.S. Strategic Petroleum Reserve (SPR) because of a severe oil supply disruption. The advantage of these event triggers is that they relate to indisputable facts (whether the event took place) and they are keyed to officially mandated mechanisms for response to an oil supply crisis.

Another event trigger could be keyed to a major disruption in Mideast oil supplies. The definition of a major disruption could be left to the Secretary, or a numerical trigger could be set. The trigger could be set as a U.S. oil import shortfall of 3 million barrels/day--the major disruption level used in the Office of Technology Assessment Report, U.S. Vulnerability to an Oil Import Curtailment: The Oil Replacement Capability (September 1984), p. 4. Another way of setting the trigger is at a specified drop in daily crude oil exports from the Mideast over a specified period (Mideast to be defined as by the EIA in the Annual Energy Review 1984 [April 1985], Table 94, p. 219).

-Retrospective Criteria Triggers

Similar to an event trigger is a retrospective criterion, keyed to one of various energy statistics over a specified period. The use of historical levels for such figures could provide some guidance, but changes in economic conditions could provide the basis for their being revised. The following criteria could be used, as applied to some reference period to be established.

(1) Imports of crude oil and refined petroleum products (excluding those for the SPR) reach a specified percentage of the trade deficit.

(2) Imports of crude oil and refined petroleum products (excluding those for the SPR) equal or exceed a specified percentage of total domestic consumption of petroleum products.

(3) The price of imported crude oil (U.S. refiners' acquisition cost as computed by EIA) increases by a specified amount or percent.

-Prospective Criteria Triggers

A prospective trigger could be keyed to oil price estimates or projections of oil import dependence. An example of such a trigger follows:

Based on the middle forecast of the EIA in its Annual Energy Outlook publication, through 1991:

-net imports of petroleum (i.e., crude oil and refined petroleum products), excluding imports acquired for the SPR, are projected to equal or exceed a specified percent of total United States domestic consumption of refined petroleum products; and/or

-oil prices (defined as U.S. refiners' acquisition cost) are projected** to
--increase by a specified amount or percent; or
--reach a specified level.

In any case, the Secretary could not accelerate a sale unless he made a finding that acceleration from triennial to biennial leasing is permissible on both environmental and multiple-use grounds.

The Secretary's decision to accelerate a sale would be conveyed to the Governors of affected States and announced in a Federal Register Notice at the initiation of the two-year presale process. Responses from Governors, localities, and other affected parties would be considered along with responses received in connection with the standard presale consultation steps, beginning with the Call. Objections to the acceleration of any sale, or reconsideration on the part of the Secretary for other reasons, could result in a decision by the Secretary to restore the sale to a triennial pacing.

-Areas Where Acceleration Could be Implemented

The eight areas proposed for acceleration in the Draft Proposed Program are listed above. For the decision on the Proposed Program, an option has been added to provide that consideration be given to the potential acceleration of sales in any area scheduled for triennial sales.

-Comments on the Flexibility (Acceleration) Provision

Alabama, Maryland, New Jersey, Virginia, New Hampshire, Connecticut, Maine, and Hawaii endorsed the proposed provision. Alabama cited the Eastern Gulf of Mexico planning area as a prime place for application of the provision. Rhode Island stated that the flexibility provision appears to be a good idea, but that more information is needed concerning it. The Department of Energy endorsed the proposed flexibility provision and urged that the provision be explained fully to avoid misunderstanding and controversy. Chevron, Marathon, Shell, NOIA, Sohio, Union Texas Petroleum, Texaco, Western Oil and Gas Association (WOGA), and Mobil generally endorsed the proposed flexibility provision. ARCO commented that the potential to accelerate sales should be available in all planning areas.

New Jersey emphasized that adequate consultation with affected States must be a part of any implementation of flexibility. Alaska and South Carolina expressed a need for more information about the flexibility provision and urged that the provision be explained fully to avoid misunderstanding and controversy. NOAA commented that the development of specific guidelines to implement the flexibility provision is of great interest to them. They also stated that acceleration of leasing in the Navarin Basin, Beaufort Sea, North Aleutian Basin, and St. George Basin planning areas should be viewed with caution. BP Alaska, NOIA, Tenneco, Sohio, Union Texas Petroleum, Exxon, WOGA, and U.S. Chamber of Commerce addressed this topic by stressing the need for overall reliability in the program. Exxon endorsed the concept of accelerating sales, but stated a wish to have sales added to the schedule or have biennial leasing at the outset. The Alaska Oil and Gas Association stated that acceleration of sales would be useful in triennial sale areas, but would not be a satisfactory substitute for scheduling frequent sales in high interest areas.

Florida commented that accelerated leasing in certain areas may conflict with the goals of the new 5-year environmental studies program. Massachusetts cited a need for more information and stated that the flexibility provision may be inconsistent with the OCS Lands Act. Oregon requested that the flexibility provision be deleted from the program. The EPA commented that the acceleration of lease sales could cause planning disruptions and uncertainty, citing NPDES permitting as a process which would be affected. They suggested that diligence requirements be changed instead of adopting the proposed flexibility provision. The California Coastal Commission and the California Department of Justice commented that the proposed flexibility provision appears to violate section 18(e) of the OCS Lands Act. The latter agency also stated that it is unclear how the provision would be implemented. The Senate Rules Committee of the California Legislature expressed strong opposition to the proposed flexibility provision. The California State Lands Commission commented that accelerating sales could strain State review of environmental impact statements.

Several California local governments noted the proposed flexibility provision in resolutions stating general opposition to the Draft Proposed Program (cited above). The City of Santa Barbara and the County of Ventura commented that the proposed flexibility provision will help bring about annual leasing. Ventura recommended that sales be scheduled no more than once every 2 years. The County of Santa Cruz commented that the flexibility provision appears to be a major step back for local governments attempting to ensure that location and timing of lease sales is consistent with protection of coastal resources. The City of San Clemente commented that the proposed flexibility provision appears to be inconsistent with the OCS Lands Act. The County of Santa Barbara stated that if a flexibility provision is included in the leasing program, it must be offset by a deceleration provision also included in the program. The City of Lompoc also suggested adding a deceleration provision. The City of Los Angeles commented that the proposed flexibility provision would result in the practice of beginning a new lease sale immediately after one is completed.

The Marin Conservation League and the California Public Interest Research Group cited the flexibility provision in resolutions expressing general opposition to the Draft Proposed Program. The Environmental Center of San Luis Obispo County and Friends of the Sea Otter commented that the flexibility provision gives the Secretary too much discretion at the cost of State and local governments. Greenpeace, the NRDC, and the Whale Center commented that the flexibility provision appears to be inconsistent with the OCS Lands Act. The League of Women Voters of San Luis Obispo commented that the flexibility provision would disrupt the entire planning process for OCS leasing. The League of Women Voters of Santa Barbara requested that the flexibility provision not be applied to leasing in the Santa Barbara Channel and the Santa Maria Basin. The Lone Star Sierra Club Chapter (Galveston, TX) commented that since economic conditions change much more rapidly than exploration and production activities, acceleration of leasing is not warranted. The Florida Public Interest Research Group commented that acceleration is acceptable, but deceleration should also be considered in the program. The Planning and conservation league and the Pacific Coast Federation of Fishermen's Associations commented that flexibility provisions should be the responsibility of Congress. A letter signed by Mel Levine, Bill Lowry, and Leon E. Panetta commented that the proposed flexibility provision may conflict with the Secretary's stated commitment to a slower leasing pace, orderly consultations, and early conflict resolution.

-Decision Options for the Acceleration Provision

OPTION 2-g Provide for the possible acceleration of OCS sales in areas of higher value and/or higher interest from a triennial to a biennial basis (but not so as to increase the total number of sales in any planning area in the approved program).

OPTION 2-g-i Propose or request comments on any or all of the following triggers for the possible acceleration of OCS oil and gas leasing

(A) Geologic Trigger: a finding by the Secretary that a new discovery in a planning area indicates that biennial leasing there is in the national interest

(B) Economic Triggers:

(I) Activation of the International Energy Agency's oil sharing agreement
(II) Drawdown of the Strategic Petroleum Reserve (SPR) because of a severe oil supply disruption
(III) Major disruption in Mideast oil shipments
(IV) Imports of crude oil and refined petroleum products (excluding those for the SPR) reach a specified percentage of the trade deficit over a specified period
(V) Imports of crude oil and refined petroleum products (excluding those for the SPR) reach a specific percentage of total domestic consumption of petroleum products over a specified period
(VI) The price of imported crude oil (U.S. refiners' acquisition cost as computed by EIA) rises by a specified amount or percent over a specified period
(VII) Net imports of petroleum (excluding those for the SPR) are projected by EIA to equal or exceed a specified percent of U.S. consumption of refined petroleum products
(VIII) Oil prices are projected by EIA to increase by a specified amount or percent or reach a specified level
(IX) Items I through VIII above
(X) Other

OPTION 2-g-ii Select areas for the potential acceleration of OCS sales

(A) Any or all of the eight areas selected in the Draft Proposed Program decision: Southern California; Central California; Northern California; Eastern Gulf of Mexico; Beaufort Sea; Navarin Basin; North Aleutian Basin; and/or St. George basin.

(B) All areas scheduled for triennial sales

3. Estimate of the Value of the Base Schedule Option

The base sale schedule (Option 2-a) presented in this section represents one of the alternatives for lease sale timing and location for the Secretary's consideration in the development of the 5-year program. The base sale schedule consists of 32 sales in 17 planning areas. As described in the options section (Part III.A.2 above), the sale schedule was derived by considering a combination of factors including: net economic value, social costs (reflecting marine productivity and environmental sensitivity), industry interest rankings, and other section 18 considerations. During the presale process, the Secretary will make a determination as to the specific size of the lease sale. The prelease sale decision on size, together with the decisions the Secretary will make on timing and location (as part of the 5-year program), will significantly influence the pace of OCS leasing and development. Consequently, these decisions will influence the timing of costs incurred and benefits realized from OCS oil and gas development. In general, the faster that leases are made available for exploration in the next 5-year program, the sooner production over the subsequent 20 to 30 years will be achieved. In addition, benefits will be higher if the lower cost resources are found and produced first. The objective of the base sale schedule valuation analysis is to establish the link between, on one hand, the rate and sequence of leasing and, on the other, the timing and the magnitude of the benefits that can be expected.

In order to quantify the impact of certain costs and benefits of the base schedule timing and location decision, an analysis was prepared which indicates the present net social value of the net benefits by accounting for the amount of resources which are projected to be leased in each of the scheduled sales for the currently used presale process of focusing on promising acreage (reflecting the decision option selected in the Draft Proposed Program). It should be noted that there is much inherent uncertainty in assessing the amount of resources expected to be leased in each sale. The methodology is discussed in Appendix R.

The sale size ultimately determined by the presale process will affect the amount of resources which are leased during the 5-year program. The rate of leasing resources which could be expected under the tract selection or areawide sale processes will differ from the projections used for the "focusing on promising acreage" process; but, as explained in section III.B., the exact differences are uncertain for many planning areas, and are therefore not assessed on a sale-specific basis for the valuation of the base schedule schedule alternatives. However, in terms of valuation of the schedule as a whole, past leasing experience indicates that the tract selection approach would result in a lower rate of resources being leased during the 5-year program than would be leased under the "focusing on promising acreage" sale process. As a consequence, tract selection sales would result in lower expectation of net social value.

Also, based on past leasing experience, the areawide sale process should be expected, on the whole, to result in a higher rate of resources being leased than under the "focusing on promising acreage" approach. This is the case because "focusing" is expected to preclude the offering of some promising acreage that otherwise could be leased. (See part III.B. for the discussion of size/presale processes). Therefore, given the base case economic assumptions, and the resulting cost of delay analysis in Appendix F, areawide leasing would increase expectations of net social value--assuming that the sales could

be held. If, however, "focusing on promising acreage" increased the likelihood that a sale would actually be held--by, for example, reducing the chances of a sale being enjoined as a result of litigation, then "focusing on promising acreage" could produce the actually higher value. This is clearly a matter of judgment for the Secretary.

Description of Analysis

The data developed for net social value were used to value the sales in the base schedule alternative. However, unlike the net social value calculation which estimated value for all leasable resources if leased at the beginning of 1987, the schedule valuation analysis required estimation of the amount of resources which would be leased at the time of each lease sale. Economic assumptions used are consistent with the base case assumptions for the net social value analysis--i.e., a base case oil price of $24 per barrel (July 1984 starting price), a 1 percent annual real oil price growth, and an 8 percent discount rate.

The amounts of resources projected to be leased in a sale within each planning area are based on those resources which are economically "developable" i.e., resources which are economic to develop, given that they have been discovered. In many cases, these projections exceed the amount of resources classified as "leasable" for purposes of calculating net economic value in Appendix F. The projections of resources expected to be leased and the estimates of leasable resources were generated for different purposes and therefore have different meaning. Estimates of "leasable" resources provide a basis for computing the measure of a planning area's net economic value for a given set of economic assumptions at the start of the next 5-year program. This measure allows for a ranking of the prospective nature of planning areas at that time.

On the other hand, the value of a particular schedule in which resources are leased over the time period beginning in January 1987 depends upon a broader set of factors than simply "leasable" resources to generate sale-specific resource acquisition. (These additional factors are described in Appendix R.)

Thus, while "leasable" resources influence the sale-specific resource levels, the aggregate amount of resources projected to be leased in a given planning area over a 5-year period is not constrained by the "leasable" resources estimated for the net economic value calculations.

In calculating the economic costs and benefits of the base schedule, it is important to take into account not only the value of the scheduled sales, but also the value of remaining unleased resources. To estimate value of the remaining resources, unleased as of the end of the new 5-year program, an assumption had to be made regarding the pace and rate of leasing in each planning area after 1991. For purposes of this valuation analysis, the pace of leasing established for each planning area in the base schedule was continued until all developable resources were exhausted. The amount of resources expected to be leased each year after 1991 was assumed to be approximately that rate projected for the last sale in each planning area. This is an improvement over the methodology used in the 1982 analysis; however, it should be noted that there is great uncertainty surrounding how or if resources would be leased in each planning area during future 5-year programs.

The resulting net social value estimates from this schedule valuation are highly sensitive to the assumptions employed. The ultimate benefits and costs associated with this 5-year program will also differ from the results of this analysis with any changes in the sale timing (e.g., postponement of sales) or with specific lease sale decisions regarding subarea deferrals and sale size in the Proposed Program. Therefore, the assumptions made for the purposes of the valuation analysis, together with the uncertainties associated with estimating economic value and social costs, should be expected to have a compounding effect on the results. Furthermore, the relative uncertainty in the results is, in part, based on the adequacy of data for each planning area. (See Table 12.1 in this SID and Appendix E.)

Table 17 is a summary of the value of the base case schedule of standard sales (option 2-a) and the value of remaining unleased resources associated with this schedule. Given the stated economic assumptions, the present net social value of resources projected to be leased during the 5-year program totals approximately $32 billion; and the value of the remaining unleased resources as of January 1987 is estimated to be approximately $21 billion.

Using the value of the base schedule as a guide, certain conclusions can be inferred about the value of alternative schedules. Each of the alternatives 2-b through 2-h would increase or decrease the value estimate for the base schedule, depending upon the nature of the option. For example, options which add sales or accelerate sales (such as options b, d, f, g, and h) would be expected, on the whole, to increase the expected net social value of the 5-year program. The increase in present net social value for schedules with earlier sales results from the effects of discounting values generated over time to account for society's time preference in exchanging consumption now for consumption in the future (@ 8 percent discount rate). In almost all cases, this benefit more than offsets the loss due to the foregone growth in value from higher resource prices. Where this is not the case, royalties, taxes and the minimum bid reduce the likelihood that such prospects would be leased and developed prematurely. Options which allow for the cancellation or deferral of subareas and sales (such as options 1-c and 2-c) would be expected to reduce the estimated present net social value the base schedule.

The calculation of net social value for the base schedule is an important indication of the economic impacts of timing and location decision for the OCS 5-year leasing program. However, this is only one of the significant factors that the Secretary will consider in his decisions on the 5-year program. Other section 18 considerations are discussed elsewhere in the SID.

Table 17

Discounted Net Social Value of the Base Schedule and Remaining Unleased Developable Resources /1
($Millions, Except Totals)

Planning Area	Discounted Net Social Value /2	
	Base Schedule	Remaining Unleased Developable Resources /3
North Atlantic	147	147
Mid-Atlantic	359	503
South Atlantic	290	855
Western Gulf of Mexico	8,489	7,513
Central Gulf of Mexico	13,859	7,544
Eastern Gulf of Mexico	499	525
Southern California	3,884	1,811
Central California	739	684
Northern California	1,267	342
Oregon-Washington	247	159
Beaufort Sea	550	19
Chukchi Sea	220	236
Norton Basin	42	12
Navarin Basin	1,058	357
St. George Basin	109	289
N. Aleutian Basin	26	4
Shumagin	10	2
Gulf of Alaska	0	45
Cook Inlet	0	10
Kodiak	0	25
Hope	0	6
Florida Straits	0	33
Totals	$32 billion	$21 billion

/1 The uncertainty associated with estimating resources and net social value, as described throughout the text of the SID and this appendix, is compounded in the formulation of a leasing schedule. Furthermore, the relative uncertainty in the numbers in this table is, in part, based on the adequacy of data for each planning area. (See Table 12-1 in this SID and Appendix E.)

/2 Net social value is discounted to January 1987--the projected start of the 5-Year Program.

/3 The values of remaining unleased resources do not include estimates of resources in currently uneconomic prospects which become economical as hydrocarbon prices increase in the future. See Appendix F, section V.C.

III.B. Size Options for the Proposed Program

Comparison of the Three Presale Approaches

Three basic presale approaches have been used for OCS general lease sales: (1) "tract selection;" (2) the initial "areawide" process; and (3) modifications of the areawide approach--most recently, focusing on promising acreage. These approaches will be described and compared with special attention to their effects on multiple-use and environmental considerations, planning and coordination with States and localities, and exploration.

The current presale process (described in detail in Appendix L) extends over a period of about 2 years.

To compare the tract selection, areawide, and focusing approaches one needs to consider a wide range of issues some of which will be addressed here and others elsewhere in the SID. Comments on this issue which were received in response to the March 1985 request are summarized in Appendix B. Fair market value considerations are discussed in Part II.E and Appendices K and P. Further data and analysis on the tract selection and areawide leasing approaches appear in Appendix P.

Overview

Historically, these different approaches represent distinguishable combinations of policies and procedures under different Secretaries of the Interior. The tract selection approach was used until 1982. The initial areawide leasing approach was used in Sale 76, held in April 1983, through Sale 79, Eastern Gulf of Mexico, held in January 1984. A modified areawide leasing approach was inaugurated in January 1984. A further modification, focusing on promising acreage was inaugurated in March 1985, with the issuance of the Draft Proposed Program.

The March 1985 Federal Register Notice announcing the Draft Proposed Program described focusing on promising acreage in the following terms:

> It is proposed that the size of lease sales be determined by a presale process which results in the offering of promising acreage. Promising acreage is that which is reasonably determined to be likely to lead to exploration and/or development of oil and gas resources. That determination will be made by means of a consultative process which will provide for the early resolution of conflicts based on information and nominations obtained from affected Federal Agencies, State and local governments, the public, and potential bidders, as well as Minerals Management Service analysis.
>
> The offering of promising acreage will give effect to DOI's desire to make available for lease areas of hydrocarbon potential as identified by industry and MMS, while remaining cognizant of the particular circumstances relevant to each sale. The various OCS areas and the adjacent onshore regions vary significantly in terms of exploration and development history, onshore support capability, and possible multiple-use conflicts. In preparing for leasing activity, regional differences will be taken into account on a case-by-case, sale-by-sale basis, and the emphasis will be on consultation, and, wherever possible, consensus.

The tract selection sale procedures used in prior years restricted the location and the amount of acreage offered, in part because of opposition to leasing and in part because of administrative constraints on the number of specific tracts that were processed through the environmental impact analysis and presale tract evaluation steps in preparing for lease sales. Tract value estimates were prepared for all tracts to be offered and were completed prior to the date of the sale. As a result of these constraints, only about half of the tracts nominated by potential bidders were offered in the subsequent sale. The tracts selected from those nominated tended to be those that received nominations from more than one or two firms.

One of the objectives of areawide leasing was to give more freedom to oil and gas exploration firms in the location and the rate of investments in exploration and development of OCS oil and gas prospects. A number of procedural changes were made in order to achieve this objective, allowing the higher leasing rates of 1983 and 1984.

The three approaches differ in two general ways. First, the acreage offered for lease tends to be largest in areawide sales and smallest in tract selection sales with focusing on promising acreage in the middle. The largest areawide sale (over 58 million acres) included about 20 times the acreage of the largest tract selection sale (about 3 million acres). Second, tract selection relies more on governmental as opposed to private industry judgment in the course of the presale process. Both the areawide approach and focusing on promising acreage give more weight to a nomination submitted by a single firm than was the case under tract selection.

Focusing on promising acreage differs from the areawide approach in that the former provides more flexibility for the resolution of conflicts early in the presale process--especially concerning low-resource, low-interest acreage. The magnitude and timing of deferrals ("focusing") from sales since January 1984 are documented in Appendix O.

It is possible to combine tract selection or areawide procedures with a variety of policies concerning the size of a sale. For example, areawide leasing procedures can accommodate sales covering a whole planning area or much smaller sales. Likewise, with the post-sale evaluation procedures in place--procedures designed for larger tract selection sales and then used for areawide sales--tract selection sales could be larger than their historical limit of 2 to 3 million acres. Nonetheless, the term, "tract selection" as used by most parties connotes the historical approach used in OCS leasing prior to 1982: sales offering generally 1 to 2 million acres.

In addition to the presale procedures for determining the amount of acreage to be offered for lease, it is possible to influence the amount of acreage actually leased in a given sale by appropriately setting the minimum bid that can be submitted. The higher the minimum bid, the lower the number of tracts of sufficient value to be worth acquiring at bids at least that high. Thus the minimum bid is in some ways an alternative or a supplement to presale procedures for controlling the actual pace and timing of leasing. The minimum bid also has competition and revenue effects and is therefore discussed in Part III.C. Other possible approaches to limiting the amount of acreage leased are described in the section on decision options regarding sale size, below.

Comments on the Size of Sales and the Presale Process

Focusing on Promising Acreage: Alabama, California, Delaware, Maryland, New Hampshire, New Jersey, New York, North Carolina, South Carolina, and Virginia generally agreed with focusing on promising acreage as a presale process. The Southern California Association of Governments and the County of Ventura endorsed the concept of promising acreage as a constructive alternative to areawide leasing. BP Alaska and Texaco stated agreement with the process. Get Oil Out, Inc. endorsed efforts to limit the size of areas proposed for lease and the Florida Public Interest Research Group commented that focusing on promising acreage offers significant improvement over the current process. NASA, NOAA, and the U.S. Department of Justice stated agreement with this presale process. NOAA emphasized the importance of early definition of geologic structures and the U.S. Department of Jutice noted that this process will provide flexibility and serve to ameliorate possible leasing concerns.

On the other hand, several California local governments submitted resolutions stating that this presale process would not permit adequate consideration of local use priorities, commercial fishing conflicts, or local agency input to leasing decisions. The City of San Clemente also expressed opposition to the promising acreage presale process. Massachusetts Audubon Society, Greenpeace, and NRDC stated their opposition to focused leasing (Greenpeace and NRDC also failed to perceive a difference between the areawide and focused approaches). The same three organizations also commented that adequate environmental impact statements cannot be written under the areawide or focused process. NRDC posed several questions requesting more specific information concerning the proposed presale process. The Marin Conservation League and the California Public Interest Group cited focusing on promising acreage in resolutions expressing general opposition to the Draft Proposed Program.

Louisiana, Rhode Island, Texas, and the Southern California Association of Governments requested clarification of the focusing on promising acreage process. Washington commented that focusing on promising acreage is an improvement over the areawide process, but does not fulfill the need for a process which provides for identification and deletion of certain areas. Florida stated that areas of deferral and actual industry interest for a sale should be decided before the draft EIS prepared for that sale is released. The City of Los Angeles commented that the concept of promising acreage will not change appreciably the leasing process for the Southern California planning area.

Shell, NOIA, API, Sohio and Exxon cited inequities in the procedures governing submission of positive and negative lease sale nominations, and they requested that the procedures be made similar for both types of nominations. Exxon and Arco expressed concern that the proposed emphasis on consensus could cause unique exploration philosophies held by one or a few companies to be ignored or discounted.

Tract Selection Sales: Alaska stated a preference for returning to the tract selection process or an analogous focused process to facilitate impact analysis. The California Department of Justice, City of San Diego, and San Diego Association of Governments also expressed support for the tract selection prelease process. Massachusetts commented that smaller sale areas should be defined to allow States to concentrate better on those areas likely to be leased.

Areawide Sales: Texas Petroleum, NOIA, Alaska Oil and Gas Association, WOGA, API, and the U.S. Chamber of Commerce stated their preference for areawide leasing.

On the other hand, Oregon reiterated a request for abandoning the areawide leasing process. The California Department of Justice and the City of San Clemente expressed opposition to the areawide process, and letters from citzens which addressed the topic presale process were against areawide leasing.

Other comments: Tenneco stated their support for early resolution of potential conflicts, but identified the "drilling window" concept applied to the Eastern Gulf of Mexico Planning Area as an impediment to exploration and development. All comments are described in further detail in Appendix B.

Presale Procedures for the Different Approaches

The key differences between the three approaches can be seen in the early presale steps. The first step in a tract selection decision process is the Call for Nominations. The Call for Nominations asks industry to nominate tracts or descriptions of areas within the Call area. Companies are requested to rank tracts or areas nominated by priority of interest (high, medium, low). The Call also requests comments from the States, other Federal Agencies, and the public regarding which tracts or areas should or should not be considered for leasing. Comments and nominations are analyzed by the MMS along with environmental profiles and data on the area, including geologic and resource data and information from resource reports requested from other Federal Agencies prior to issuance of the Call for Nominations.

After consultation with affected States, there is a tentative selection of tracts or areas to be analyzed further in the EIS as the proposed Federal action. The tract selection approach usually narrowed down the size of the sale area to tracts or areas rated high or moderate in geologic potential by the MMS and tracts or areas nominated by a number of firms determined on a sale-specific basis up to the maximum administratively-determined size of the sale. A tract or area nominated by a single firm, even if ranked high priority by the firm, was not assured of selection for further study (even before the questions of multiple-use and environmental protection were reached). In the past, the maximum size of tract selection sales was between 2 and 3 million acres.

Under the initial areawide approach, the Call for Nominations was replaced by the Call for Information. The Call for Information can request information and expressions of interest (nominations) on virtually an entire planning area and on MMS's identification of the area of hydrocarbon potential within the planning area, as well as information on particular tracts or areas.

A modification of the areawide approach was the transition from the Call for Information to the Call for Information and Nominations which was made with the publication of the Call for Sale 109, Barrow Arch (50 FR 3870, January 28, 1985).

Focusing on promising acreage contemplates the further modification in which Call areas could be tailored on a case-by-case basis to exclude parts of the planning area. For example, the Call for Sale 110, Central Gulf of Mexico, and the 1987 Western Gulf of Mexico sale excluded the environmentally sensitive Flower Garden Banks from the Call area.

In both the areawide and focusing approaches, potential bidders are asked to outline areas or tracts in the planning area, within or beyond the area of hydrocarbon potential depicted by MMS in the Call, which they believe to have hydrocarbon potential and in which they might be interested in leasing. All interested parties are requested to comment on possible environmental effects and use conflicts. The scope of the information obtained by MMS ranges from broad area information to tract-specific information. In the focusing approach, other information may be solicited in a more precise form. For example, information from potential bidders has been requested on areas which had been deleted in past sales in the same area.

The Area Identification step is a formal decision on the area whose offering is analyzed as the proposed action in the EIS. This step roughly corresponds to the tract selection step. The information received from the Call, along with other information, is used to decide what areas, if any, should be deferred from further consideration at that point.

MMS uses the responses from potential bidders to identify promising areas, taking into account the collective judgment of the oil and gas industry as well as its own. In the case of the initial areawide approach, MMS added to that promising acreage other acreage which was not nominated which filled out a broad area outline. The focusing approach, in part, concentrates more on geological basins as identified by MMS and industry responses to the Call, omitting areas where MMS sees no hydrocarbon potential and resolving problems or conflicts that have been identified. For example, 61.2 million acres were deferred in the Area Identification decision for Sale 111, Mid-Atlantic.

The Size Range of Areas Selected, Identified, Offered, and Leased

-Examples

The following statistics are provided to illustrate the range of the size of the area identified as the proposed Federal action, the area offered, and the area leased under each presale approach.

Under the tract selection approach, the acreage selected in the tract selection step ranged from about 400,000 acres to about 3 million acres. The acreage offered had about the same range. The area leased ranged from about 300,000 acres to about twice that amount.

The largest area identified under the initial areawide process was in Sale 79, Eastern Gulf of Mexico, about 58 million acres, while the smallest was in Sale 76, Mid-Atlantic, which identified 25.4 million acres. The areas offered by those sales were 50,632,000 and 22,671,000 acres, respectively. The area leased in the first sale was 898,000 acres and in the second, 211,000 acres.

Reflecting revisions made under the modified areawide approach, the smallest modified areawide proposal (Sale 92, North Aleutian Basin) identified 5.7 million acres (about 17 percent of the planning area). The largest modified areawide proposal (Sale 94, Eastern Gulf of Mexico) identified 50.8 million acres (which is 7.2 million acres less than Sale 79 identified in the same area). In terms of the size of the planning area, Sale 79 identified the entire planning area, whereas Sale 94 identified about 88 percent of the planning area. It is illustrative of the flexibility of focusing on promising acreage that the decision on the proposed Notice of Sale for Sale 94 reduced its area from the over 50 million acres identified for study to about 37 million acres, based on coordination with affected States and other parties. Neither Sale 92 nor Sale 94 has been held yet.

Focusing on promising acreage may well be characterized by an even wider range. In the Central and Western Gulf of Mexico, DOI has been evaluating the possibility of restricting leasing to within 2,400 meters water depth. In the Final Notice for Sale 98, Central Gulf of Mexico, and Sale 102, Western Gulf of Mexico, blocks in water depths greater than 2,400 meters were deleted from the sales. In Sale 102, however, four blocks were leased which touch the 2,400 line and two were leased which are located 3 miles from the 2,400 meter line. Furthermore, in comments in response to the Call for the 1987 Gulf of Mexico sales, five companies expressed high or moderate interest in acreage deeper than 2,400 meters. For those 1987 sales (Sale 110, Central Gulf of Mexico and the 1987 Western Gulf of Mexico Sale), the 2,400 meter line was not imposed at the area identification stage.

-Limits on Projections

Examples like those given above are illustrative of the different presale processes. Projections of future outcomes, however, cannot be performed with great precision because the "presale process" is an abstraction whose concrete implementation can lead to very different results in different planning areas. The results of the presale process is likely to differ both as between planning areas and as between sales in the same planning area because they depend on the following variable factors: (1) MMS and industry estimates of the amount and distribution of undiscovered oil and gas resources in an area; (2) environmental and multiple-use considerations; and (3) the results of consultations with numerous parties, including coastal State Governors, under section 19 of the OCS Lands Act. All three factors are subject to different perceptions by the various parties who participate in the offshore leasing process. The third factor, depending as it does on a consultation process, does not lend itself to reliable predictions.

For example, the implications for sale size of multiple-use considerations such as the location of Department of Defense (DOD) use areas are subject to change based on consultation. In addition, different local attitudes toward oil and gas leasing and other uses of the ocean can lead to very different outcomes of consultations between the Department of the Interior and other parties such as coastal State Governors under section 19 of the OCS Lands Act. Both the Gulf of Mexico and Pacific regions contain significant deposits of commercially

recoverable hydrocarbons under nearshore waters. The large size of Gulf of Mexico areawide sales and the small size of, for example, Sale 80, Southern California (657 tracts), held under "areawide" procedures, clearly illustrates the effect of factors whose implications for the size of a lease sale are not clearly predictable.

Furthermore, in considering the precision with which "leasing activity" can be planned for under section 18(a) of the OCS Lands Act, it is also important to keep in mind the wide gap between offering tracts and leasing them. In the Mid-Atlantic Sale 76, over 22 million acres were offered, but under 1 percent of that area was leased. In the Eastern Gulf of Mexico Sale 79, over 50 million acres were offered, but less than 2 percent of that area was leased. Even in the OCS sale which leased the largest number of tracts (Sale 72, Central Gulf of Mexico), the 623 tracts leased represented just over 8 percent of the acreage offered. Additional examples appear in Appendix O. Among the numerous factors which influence the number of tracts actually leased are the state of the economy, future oil price expectations, individual company strategies, and exploration results in the planning area and in other planning areas. These variables add to the uncertainty in planning the size of leasing activity.

Planning and Coordination with States and Local Governments

Experience with areawide and focusing as well as tract selection sales held to date indicates that in all areas of the OCS, States are able to identify the parts of the proposed sale areas--down to specific blocks--which are of greatest concern to them for environmental or economic reasons. Nonetheless, numerous State and local governments commented that the Federal Government's--and their own--ability to analyze the effects of and coordinate with other governments concerning the offering of broad areas are strained and exceeded as the size of those areas expands (see Appendix B).

In its report entitled "Early Assessment of Interior's Area-Wide Program for Leasing Offshore Lands," the GAO summarized the results of a survey of oil and gas companies, coastal States and national environmental and fishery groups. The GAO concluded that most regarded Interior's planning documents for presale decisions as accurate and complete. Furthermore, most of those questioned believed that the time for review and comments was still adequate.

Multiple-Use Conflicts and Environmental Considerations

The offering of broad areas under the areawide leasing approach heightened the relevance of multiple-use issues. Multiple-use of the OCS is the subject of numerous comments summarized in Appendix B. Multiple-use and environmental considerations are treated generally in Appendices G and H and will be treated more fully in the EIS.

The presale process presents opportunities to receive information on and conduct consultations concerning multiple-use and environmental considerations. Decisions on the size of the Call area and the Area Identification provide the occasion for the early resolution of conflicts over these issues. The focusing approach emphasizes the use of these early decision points to resolve such conflicts that cannot be mitigated through other means--especially with respect to low-resource, low-interest blocks.

During the presale process, MMS coordinates with numerous parties who use the OCS, for example, the Coast Guard, the Navy, and the Air Force. In response to Navy concerns about conflicts in Warning Area 155, a deferral of about 1.4 million acres was made from Sale 94, Eastern Gulf of Mexico. To mitigate operational conflicts with the Navy further, a stipulation has been developed for Warning Area 174 in the southern part of the planning area to restrict spacing of structures during exploratory drilling to allow unimpeded Navy carrier training exercises.

To mitigate use conflicts with Air Force operations in the Eglin Water Test areas, a "time-sharing" stipulation has been developed which sets forth restrictions creating limited, phased access for exploratory drilling. Several "information to lessees" clauses also alert bidders to special concerns regarding other defense-related operations.

The EIS under both the areawide and focusing approaches reviews deferral options as well as measures (such as stipulations) to mitigate potential adverse effects of development on a site-specific basis.

Appendix O documents presale deferrals from sales in the current 5-year program.

Effects on Exploration of the Different Presale Processes

Section 102(9) of the OCS Lands Act Amendments provides that one of the purposes of that act is to "insure that the extent of oil and natural gas resources of the Outer Continental Shelf is assessed at the earliest practicable time." One objective sought when areawide leasing was adopted in 1982 was to expand the amount and location of acreage leased and thus to allow an increase in the rate of investment in exploration. Thus, it is appropriate to consider the effect of the different presale approaches on future exploration of the OCS.

In the Central and Western Gulf of Mexico, lease issuance proceeded under the tract selection procedures at a rate of about 1 million acres per year during the late 1970s and early 1980s. Almost twice as much acreage was offered--about 1.7 million acres per year--as was leased during that same period. Despite the nomination and tract selection process, only half of the acreage selected as promising 20-some months prior to each sale proved worth bidding upon after further evaluation by firms. Areawide leasing expanded the acreage offered in the Gulf of Mexico by a factor of 35. Acreage leased expanded from 1 million acres per year to about 5 million acres. This shows a very substantial increase in the amount of acreage evaluated, bid upon, and acquired by offshore lessees.

The comparison of postlease exploration activity suggests that areawide leasing has had a favorable effect on investment in exploratory drilling. Although leases resulting from areawide Sales 72 and 74 have been in existence only a short time, drilling activity, based on the number of leases drilled, seems to be proceeding at a higher rate than it did as a result of previous tract selection sales (see Appendix P). The GAO report on areawide leasing also examined the effects on exploration. It concluded that "exploration is progressing at a faster rate under the area-wide program." This report includes data showing that more tracts had been drilled from Gulf of Mexico

Table 18

Producing or Producible Tracts Containing Surface Area Leased More Than Once

Area	Sale	Number of Producing or Producible Tracts Previously Leased
Gulf of Mexico (GOM)	84	None to date
	81	None to date
	74	4
	72	14
	69 Part II	None to date
	69 Part I	6
	67	4
	66	5
	A66	15
	62	1
	A62	14
	58A	12
	58	7
	51	14
	Pre-51	57
	GOM Total	153
Pacific	80	None to date
	68	1
	48	1
	Pacific Total	2

areawide Sales 72 and 74 than from any recent tract selection sales. In addition, a majority of oil and gas companies responding to GAO's questionnaire said that areawide leasing would facilitate exploration and that they have greatly increase their exploration in the Gulf of Mexico as a result.

The areawide approach maximizes the industry's ability to utilize the most up-to-date exploration data and interpretations providing greater flexibility to bid on areas that were of little interest 2 to 3 years prior to the sale, when the Call would have been issued. The areawide approach thus allows the incorporation of late-developing exploration data into both government and industry presale planning more than was the case with the tract selection approach.

Under focusing on promising acreage, the early resolution of conflicts regarding acreage deemed to be low-value and low-interest can result in the exclusion of acreage about which potential bidders could change their opinion by the time of the sale. For example, in areawide Sale 79, a small number of blocks received bids in what had been identified as a low-value, low-interest area.

It is also worth noting that in areawide sales, blocks that had been previously leased and relinquished were again leased. Some were never tested, some were explored but the amount of hydrocarbons discovered was not economical to produce at that time, and others were produced but had not been drilled to horizons now considered prospective. With the present economic conditions, these reoffered tracts are again attractive to industry (see Table 18). A tract selection approach would not have ensured the reoffering of these blocks as soon as under the areawide approach.

While areawide leasing substantially increased the acreage leased and the rate of investment in exploration, continuation of areawide leasing in the 1986-1991 period may not result in leasing and exploration at the rates achieved in the 1983-1985 period. As Appendix P describes, the substantial increases in areas leased that resulted from early areawide sales reflected leasing from an unleased inventory of attractive prospects for drilling that had been built up by the combination of price increases and the smaller offerings under the tract selection procedures in the 1976-1982 period. The substantial amount of leasing that will have occurred in the 1983-1987 period, coupled with substantial decreases in oil price expectations, could leave an unleased inventory with far fewer attractive prospects for the 1987-1992 period. Even with these changed conditions, providing industry with a wider range of choices through a form of areawide leasing could still lead to the testing of more diverse exploration strategies than under a tract selection approach.

Flexibility

The areawide approaches allow more flexibility to increase rapidly the amount of acreage offered if oil prices increase rapidly again. This could be particularly true if the administrative processes for restricted sales were to be accompanied by reduced administrative capacity (budget and manpower), placing constraints on increases in the acreage to be offered.

The tract selection procedures of the 1970s made it difficult to increase the acreage offered when conditions warranted. The leasing experience of the 1970s shows that the longer the restriction in the availability of prospective acreage, the greater is the buildup of demand for investment and the greater

the potential jump in the rate of investment when acreage is finally made available. The rapid increases in seismic evaluation, acreage leased, and exploratory drilling in 1983 and 1984 could have been smoothed out over 5 or 6 years had more acreage been made available starting in 1977 or 1978.

In summary, the investment consequences of differences in the pace of lease offerings will tend to be greater the more rapid and extensive are the changes in oil price expectations and geological knowledge. Restricted offerings tend to perform adequately in a relatively stable world while wider offerings allow more flexibility for investments to adapt to changing conditions.

Effects of Different Rates of Leasing on Bidding and Revenues

As described in Appendix P, the rates of leasing that result from different presale procedures can affect statistics such as the average bid per acre and the average number of bids per tract. For example, the average number of bids per tract may be less in large sales than in small sales. The MMS tract evaluation and bid rejection procedures tend to focus on tracts with fewer bids in order to provide added assurances for achieving fair market value. The analysis also shows, however, that both the level of competition and the amounts bid are strongly influenced by the economic value of the inventory of tracts offered for sale.

The set of tracts offered depends upon the size of the sale and nature of acreage remaining to be leased after previous sales. Thus, if relatively little acreage has been offered while tracts appreciated in value, the value of tracts offered could generally increase. Similarly, large sales would tend to offer many more modest and low value tracts along with the high value prospects that would tend to be offered in smaller sales. Average bid statistics reflect these differences, with bids declining as areawide and focused sales proceeded, particularly in the Gulf of Mexico where a sizable unleased inventory of attractive prospects had accumulated. Declines in the average bid due to such effects are not indicative of failure to meet the fair market value requirement.

Changes in economic conditions and the physical or geological characteristics of the tracts leased can also occur over a period of leasing. If such changes generally reduce the economic value of the tracts offered in subsequent sales. average bids will decline. The decreases in oil price expectations since 1982 and the trend toward leasing more tracts in deeper water having smaller prospects or in higher cost areas contributed to the decline in average bids evident in the 1982-1984 period. Again, declines caused by such changes in the economic value of the tracts offered and bid upon are not indicative of a failure to satisfy the fair market value requirement.

The GAO report on areawide leasing includes a statistical analysis of competition and bonus revenues under tract selection and areawide leasing. It concludes that the average number of bids declined from 2.55 per tract in tract selection sales to 1.65 in the areawide sales it reviewed. It also finds that the tract selection sales between November 30, 1979, and April 25, 1983, had an average bonus of $2,624 per acre whereas the areawide sales between April 25, 1983, and September 30, 1984, had an average bonus of $686 per acre. Of the $1,738 per acre difference, the GAO estimated that $541 was caused by the shift to areawide leasing while $1,397 was due to other factors. On this basis the GAO estimated

that the Federal Government received $5.4 billion (discounted to 1984) less for the tracts leased in the first ten areawide sales than it would have received if the same acreage had been leased using tract selection sale procedures.

The GAO report notes that the OCS Lands Act "does not require Interior to maximize government revenues for offshore leases," though revenues are an important consideration. The GAO observes that under tract selection, industry "paid a premium" which it "has been less willing to pay" under areawide leasing. It also acknowledges that "some of the estimated reduction in bonus revenue due to the increased pace of areawide leasing will be offset by earlier receipt of royalties, rents and taxes which continue for many years after a tract is placed in production." The GAO analysis has been reviewed by MMS, as set forth in the letter to the Honorable Jack Brooks, Chairman of the Committee on Government Operations of the House of Representatives, signed by MMS Director Bettenberg on September 30, 1985, which is included in the SID by reference.

Appendix P provides more recent data on leasing and exploration, and reports preliminary efforts to estimate the effects of earlier receipt of non-bonus revenues. It identifies a number of deficiencies in the statistical analysis which seriously undermine confidence in the GAO's estimate of the bonus reductions caused by areawide leasing. While many of these deficiencies are highly technical, the difficulty of isolating the bonus effects of areawide leasing from the effects of other factors can be gauged from the difficulty in measuring some of these other factors. For example, bidders' expectations about future oil and gas prices have been changing substantially during the 1979-1985 period. It is unlikely that such changes in bidders' expectations are accurately measured by forecasts of future prices by MMS or any other individual forecaster.

Similarly, it is unlikely that measures of the resource potential of the tracts leased accurately reflect the variations in individual bidders assessments of the resources, given the mixed results of exploration in recent years. Changes in firms optimism about the prospects for new discoveries would clearly affect their bids (and the level of competition) but are difficult to measure for purposes of a statistical analysis.

Appendix P summarizes preliminary analyses by MMS of the overall revenue effects of earlier leasing and shows the substantial gains to the Treasury that can be realized. The leasing in the Gulf of Mexico is the best example of such effects. In 1983 and 1984, 1,029 tracts were leased in the Gulf of Mexico under the areawide and promising acreage approaches. Had these same tracts been leased under the tract selection approach, which typically leased 200 tracts per year, it would have taken about 12 years to complete their leasing. All of the revenues--bonuses, rents, royalties, and taxes--paid as a result of these leases occur earlier (except, of course, the revenues form the 200 tracts that would have been leased in 1983 under tract selection). In fact, revenues from the last 200 tracts leased in 1985 have been moved up by about 9 years. Appendix P shows that, because of these gains to the Treasury, areawide leasing could have reduced bonuses by as much as $8.5 million per tract without causing an overall loss.

Furthermore, leasing and search for oil and gas is a sequential process in which new prospects are identified each year using the results of exploration from previous years. Tract selection leasing would have limited the rate at which industry searched through the many prospects made attractive by the price

increases of the 1970's. Areawide leasing in the 1983-1985 period has made it possible to advance the exploration of all resources that are currently economical by as much as 9 years. Further advances will be realized for as long as the areawide leasing and exploration rates exceed those that would have resulted form tract selection leasing. These advances in the timing of the development of all currently economical resources yield gains in increased economic benefits. It is difficult to specify with much certainty the economic conditions and resource development over the next four decades, even in the Gulf of Mexico. However, under reasonable assumptions, it appears that advances in development under areawide leasing could yield gains of $8 to $12 billion in the present value of oil and gas realized from resources yet to be leased in the Gulf of Mexico.

As of October 7, 1985, 17 comments have been received on Appendix P (as revised on July 15, 1985) in response to the August 19, 1985, Federal Register Notice. The responses of Maryland and Connecticut both question the validity of using data from a mature producing area, the Gulf of Mexico, to draw conclusions about areawide or tract selection leasing for frontier areas. Maryland again recommended that a 50-mile buffer be established for use of the tract selection process within that buffer and the use of the areawide process outside it. Respondents from three State agencies expressed continued opposition to areawide leasing. The Maine State Planning Office stated that the appendix was more a response to areawide leasing critics rather than a policy analysis. New Jersey still supports focused leasing, and Louisiana favors a steadier paced leasing program rather than an accelerated program. California finds that there is little data specific to the areawide leasing consequences for that State.

Because Virginia offshore resources were not involved, the Virginia Deputy Secretary of Resources stated that he would not comment. The NRDC disagreed with certain DOI assumptions, particularly the 8 percent discount rate used throughout the 5-Year Plan and asserted that the profit sharing approach should be examined as an alternative to the cash bonus approach. The Department of Energy, the only Federal Agency to respond, concluded that areawide leasing has increased the present value contribution of total OCS payments to federal revenues by about $3.5 billion compared to tract selection. Their review of the GAO study uncovered significant errors that caused GAO to reach incorrect conclusions. The five respondents from industry all support the areawide leasing approach and basically concur with the Appendix P analysis.

-Decision Options for the Proposed Program

OPTION 3-a Focusing on Promising Acreage

OPTION 3-a-i Use the presale approach of focusing on promising acreage

The process of focusing on promising acreage is described above. It is a flexible approach whose results can range from "areawide" size sales to "tract selection" size sales, depending on MMS resource estimates, industry nominations, environmental issues, and use conflicts. A presale process of focusing on promising acreage provides an alternative and/or supplement to the deferral of subareas at the 5-year program stage for the purpose of achieving an early resolution of conflicts.

OPTION 3-a-ii Solicit comments in the Federal Register Notice announcing the Proposed Program on possible techniques for implementing that approach.

Focusing on promising acreage is an approach open to the development of new techniques for the resolution of conflicts concerning the size of sales. This suboption provides for the solicitation of comments from State and local governments, the oil and gas industry, Federal agencies, and the general public on any or all of the following:

(A) - The recommendation of the Governor of Maryland that the presale process combine the tract selection approach for blocks within 50 miles of shore and areawide procedures for blocks beyond that limit. The advantage of this approach would be responsiveness to coastal States' requests for greater assurance that detailed consideration will be given to areas of greatest concern to them. The disadvantage of this approach is the arbitrariness of the 50-mile figure. If a less arbitrary limit were set, however, it would probably be at the cost of the clarity of the 50-mile proposal.

(B) - Other combinations of areawide and tract selection approaches could also be considered, such as the offering of large amounts of acreage in areas where there have been discoveries and the the offering of smaller amounts of acreage in frontier areas. It has been asserted that this approach could yield nearly the same leasing as the current approach but, by reverting to tract selection in frontier areas, might reduce environmental concern and opposition to leasing. Tract selection sales in frontier areas could offer as much as 4-to-5 million acres, thus assuring the inclusion of most frontier area tracts of interest to bidders. The primary disadvantage of tract selection is the exclusion of substantial acreage early in the presale planning process, limiting bidding to acreage deemed promising on the basis of information that is more than a year old at the time of the lease sale.

(C) - The recommendation of the Governor of Maine that industry nominate in units of 100 blocks. The 100-block nomination units could provide relatively discrete areas for industry indications of interest which would be larger than the nine square miles of a standard block and less than the whole planning area. This approach would help industry protect their proprietary data on specific tracts during the nominations process. Since it may not be practical to establish a limit on the number of such 100-block units which could be nominated, only areas of no real concern to nominators might be screened out. A difficulty with the 100-block unit approach is the arbitrariness of its size. Another consideration is whether this approach is relevant to all planning areas, since at least some companies have nominated the whole planning area or most of it in past sales, for example, in the mature Central and Western Gulf of Mexico.

(D) - The recommendation of Massachusetts that nomination procedures be revised so as to request more detailed information from industry on areas of interest. While MMS currently has a process for gathering a great deal of information from companies, part of that process involves oral elaboration of written comments by the companies. There are always pros and cons of providing for oral as opposed to written communications with the public. Further issues to be considered here include the possibility of instituting a second nomination round late in the presale process and further discussions with States on the advantages of their concluding agreements with the DOI providing for the inspection of proprietary data under section 26 of the OCS Lands Act.

(E) - The recommendation of the API, NOIA, and a number of oil and gas producers that nomination procedures be revised so as to request more detailed information concerning "negative nominations." The object of such a request would be to elicit additional information useful for the Secretary's sale-specific decisions under the OCS Lands Act. Issues to be considered include whether public commenters have the capability to provide detailed information which may be costly to acquire; and the degree of sufficiency of the store of data already available to MMS through over $400 million worth of environmental studies performed to date.

(F) - Proposals to limit the amount of acreage leased through limiting the award of leases. For example, after deferring blocks, as appropriate, in order to avoid environmental and multiple-use conflicts, offer the remaining blocks, but place a cap on the number of leases to be awarded corresponding to a percentage of the total planning area or a fixed number determined on a planning area basis, with leases to be awarded in the order of the high bids. On one hand, this approach could provide more predictability of the maximum potential amount of leasing activity. On the other hand, setting a limit on the number of leases to be awarded may be arbitrary both as applied to a particular sale and insofar as it may be seen as a precedent for other sales, even though the original reasons for setting it might not be applicable.

(G) - Items A through F above

(H) - Other

OPTION 3-b Tract Selection Sales

OPTION 3-b-i Hold sales based on tract-specific nominations generally offering up to 2 million acres.

OPTION 3-b-ii Hold sales based on tract-specific nominations with actual acreage offered dependent on the magnitude of nominations, hydrocarbon potential, and environmental and multiple-use considerations.

OPTION 3-c Hold areawide Sales

For the purpose of this option, "areawide sales" has the meaning of the initial areawide approach described above.

OPTION 3-d Other

III.C. Minimum Bid and Bid Adequacy Review Options for the Proposed Program

Section 18(a)(4) of the OCSLA requires the formulation of an OCS leasing program consistent with the principle that

> leasing activities shall be conducted to assure receipt of fair market value for the lands leased and the rights conveyed by the Federal Government.

As discussed in Appendix K, the development of the existing 5-year leasing program included substantial revisions to the policies and procedures for meeting this requirement. The 1982 5-year program was challenged in court on the the grounds that areawide leasing would reduce competition and reduce lease bonuses and that the revised policies and procedures for deciding whether to accept or reject high bids represented an abandonment of previous tract evaluation procedures. The court, in California v. Watt (II), rejected this challenge, finding that it was reasonable for the Secretary to combine reliance on the competitive bidding process with the proposed tract evaluation and bid rejection procedures in order to meet the fair market value requirement.

In 1984 and 1985, modifications were made to the OCS bid adequacy procedures to incorporate knowledge gained from their actual use in areawide lease sales. In addition, the Department is continuing to evaluate the consequences of areawide and modified areawide leasing to determine their effects on revenue receipts and cash bonuses bid for tracts. This analysis is summarized in Appendix P.

The current bid adequacy procedures are described in detail in Appendix K. Where appropriate, the procedures continue to rely on competitive market forces to assure the receipt of fair market value. However, tracts which fall into certain identified categories, are subjected to additional independent Government analysis to assure that the high bids received adequately reflect the fair market value.

The MMS conducts evaluations of these procedures independently of this leasing program formulation. However, in developing the new 5-year leasing program, there is an opportunity to review the current procedures, evaluate their performance in conjunction with decisions about the size and timing of lease sales, and consider means for continuing to assure that fair market value will be received.

One such evaluation which is being considered for the Proposed Program is a June 7, 1985, draft paper, Analysis of Minimum Bid Policies, which is described in both Appendix F and Appendix K.

In the minimum bid analysis, the current $150 per acre minimum bid level was assessed to determine its effect on:

1. bidding and Government receipts;
2. the appropriate timing for the leasing and development of prospects in different OCS areas; and
3. promoting exploration in high-risk/high-cost areas.

One of the conclusions from the analysis is that the $150 per acre minimum bid requirement has provided an important supplement to bid adequacy procedures and has contributed to significant increases in aggregate bonus revenues. However, it should be noted that higher minimum bid levels can influence the amount of competitive interest for certain tracts and hence influence the number of bids received on these tracts.

The minimum bid analysis also indicated that the minimum bid level is an important policy tool which can be tailored for specific planning areas to encourage efficient exploration and development of OCS oil and gas resources. From the standpoint of economic efficiency, a tract should be leased if its net economic value as developed today is greater than if developed in all future periods. Conversely, leasing of tracts should be delayed if the net economic value is higher if developed in some future period.

Because oil and gas are exhaustible resources, their real value tends to rise over time. This means that the leasing and subsequent development scenario which is best for the Nation may involve a delay in the sale of certain high cost prospects in a planning area even while investments are proceeding on lower cost prospects. Absent some mechanism to prevent the leasing of certain high cost prospects, tracts with positive private value could be leased and subsequently developed too soon, partly because of diligence requirements. In light of this information, it may be desirable to retain these prospects in the Government's inventory until the time when their sale would produce maximum net benefits to the Nation. A model has been designed which will analyze the appropriate size of the minimum bid under different economic conditions. Though use of the model, the minimum bid level can be employed to filter out tracts which, according to MMS estimates, may be better retained until later in time.

The minimum bid was also identified as an important potential tool for promoting exploration in high-risk/high cost areas. Due to high risks and information externalities, there is a tendency for the private market to relatively undervalue and hence lease less acreage in frontier areas vis-a-vis proven areas. To account for these effects, it may be appropriate to consider lower minimum bids in high risk areas during earlier sales in the 5-Year Program.

However, this finding is inconsistent with the conclusion described above, that there may be some benefits to the Nation in discouraging bidding in certain high-cost areas. Therefore, the objectives of encouraging exploration in high-risk/high cost areas and the objective of leasing based on economic efficiency may be at odds for certain planning areas; and the determination whether or not the minimum bid should be lower or higher would need to be made on a sale-by-sale basis.

Since the minimum bid level has the property of influencing the amount and types of tracts (e.g., deepwater or shallow water tracts) which could be leased, a 5-Year Program decision on lease sale size could be made with consideration to varying the minimum bid. In this way, those concerns surrounding premature leasing; and to a limited extent, concerns surrounding fair market value, could be alleviated with an appropriately set, sale-specific, minimum bid.

Two decision options have been developed for the Proposed Program which reflect the policy implications of minimum bid level and bid adequacy review procedures for the receipt of fair market value, economic efficiency, and for frontier exploration issues. The options presented for decision are as follows:

4. Minimum Bid Options:

    a. Maintain the $150/acre minimum bid and determine on a sale-by-sale basis what changes, if any, are to be made; and

    b. Other.

5. Bid Adequacy Review Options:

   a. Maintain current bid adequacy review procedures and determine on a sale-by-sale basis what changes, if any, are to be made; and

   b. Other.

The selection of options 4-a and 5-a would maintain the current minimum bid policy and the current bid adequacy procedures adopted in the Secretarial decisions of March 11, 1982, (and the May 4, 1982, subsequent decision), until changes, if any, were made for individual sales.

APPENDIX A

LEGAL ASPECTS OF THE NEW PROGRAM

LEGAL ASPECTS OF THE DEVELOPMENT OF THE NEW PROGRAM

I. Discussion of Compliance with Section 18

Section 18 requires that the Secretary base his decision on the 5-year OCS Oil and Gas Leasing Program on the consideration of a number of factors. Judicial guidance as to how that requirement is to be carried out was provided by the U.S. Court of Appeals for the District of Columbia Circuit in California v. Watt (I) (668 F.2d 1290 (1981)) and California v. Watt (II) (712 F.2d 584 (1983)). The following discussion explains how the requirements of section 18 are being addressed in the decision material being provided to the Secretary, as well as in documents which will be prepared subsequent to his decision on the Proposed Program. A note of caution is necessary in reviewing this material. While each aspect of section 18 is discussed individually, a judgment with respect to any one aspect cannot be made in isolation from the others. Most are interrelated and must be considered collectively.

1. 18(a)

a. Requirement

"The Secretary, pursuant to procedures set forth in subsections (c) and (d) of this section, shall prepare and periodically revise, and maintain an oil and gas leasing program to implement the policies of this Act. The leasing program shall consist of a schedule of proposed lease sales indicating, as precisely as possible, the size, timing, and location of leasing activity which he determines will best meet national energy needs for the five-year period following its approval or reapproval."

b. Compliance

The schedule options in Part III are described in terms of timing and location of leasing activity. The size of sales is treated separately under size options. All sale designations have been reviewed in order to conform with the court's guidance on the requirement that they be described "as precisely as possible" at the leasing program stage. The role of the leasing program in addressing national energy needs is discussed in Part II.A and B and Appendix F.

Whatever schedule the Secretary adopts as the Draft Proposed Program will be appropriately described in the material transmitting it to the Governors of coastal States and in a Federal Register Notice.

2. 18(a)(1)

a. Requirement

". . . [S]uch leasing program shall be prepared and maintained in a manner consistent with the following principles [18(a)]:

(1) Management of the outer Continental Shelf shall be conducted in a manner which considers economic, social, and environmental values of the renewable and nonrenewable resources contained in the outer Continental Shelf, and the potential impact of oil and gas exploration on other resource values of the outer Continental Shelf and the marine, coastal, and human environments."

b. Compliance

The environmental impact statement (EIS) on the new 5-year program will discuss these values and the potential effects of oil and gas exploration, development, and production on them. In addition, the information considered for section 18(a)(2) and included in Part II and Appendices G, H, and I addresses the values to which this subsection of the statute refers.

3. 18(a)(2)

a. Requirement

". . . [S]uch leasing program shall be prepared and maintained in a manner consistent with the following principles [18(a)] . . . .

(2) Timing and location of exploration, development, and production of oil and gas among the oil- and gas-bearing physiographic regions of the outer Continental Shelf shall be based on a consideration of--

(A) existing information concerning the geographical, geological, and ecological characteristics of such regions;

(B) an equitable sharing of developmental benefits and environmental risks among the various regions;

(C) the location of such regions with respect to, and the relative needs of, regional and national energy markets;

(D) the location of such regions with respect to other uses of the sea and seabed, including fisheries, navigation, existing or proposed sealanes, potential sites of deepwater ports, and other anticipated uses of the resources and space of the outer Continental Shelf;

(E) the interest of potential oil and gas producers in the development of oil and gas resources as indicated by exploration or nomination;

(F) laws, goals, and policies of affected States which have been specifically identified by the Governors of such States as relevant matters for the Secretary's consideration;

(G) the relative environmental sensitivity and marine productivity of different areas of the outer Continental Shelf; and

(H) relevant environmental and predictive information for different areas of the outer Continental Shelf."

b. Compliance

Compliance with item (A) regarding existing information is reflected throughout the SID and appendices and addressed in particular in Appendices G, H, and I. It will be addressed further in the EIS.

The framework for addressing Item (B), the equitable sharing consideration, is discussed under Part II.C. This discussion draws upon the analysis of the estimated social and regional costs associated with potential environmental damages and the estimated net economic value associated with each planning area found in Part II.B and Appendices E, F, and G. The analysis of estimated social and regional costs addresses potential damage from oil spills including ecological damages, losses to tourism, recreation, commercial fishing, and clean-up costs. That analysis in turn, rests in part on the analysis of the relative marine productivity and environmental sensitivity of the different areas of the OCS and their respective adjacent coastlines. It also covers potential losses due to air pollution, commercial fishing conflicts and potential losses of habitats due to onshore support activities. Potential damages for which dollar cost estimates were not made must also be considered. The analysis of relative marine productivity and environmental sensitivity is also useful in considering these potential damages. Qualitative descriptions of the potential effects of leasing activity will be included in the EIS.

Item (C), which includes consideration of the location of the regions relative to regional and national energy markets and their needs, was addressed initially in an early stage of the reapproval process. The Secretary's letter of July 5, 1984, to the Secretary of Energy specifically asked the Department of Energy to comment on this consideration, as well as on the availability of current and projected transportation networks. An analysis of availability of transportation to bring resources from various OCS areas to regional and national energy markets may be found in Appendix J. Further analysis of national energy considerations may be found in Part II.A and Appendix F. The social and regional costs of transportation systems are considered in Part II.B and Appendix G, and will be further analyzed in the EIS.

Item (D), concerning the location of planning areas with respect to other uses, is covered in Appendix H, which describes these other uses by planning area. Where possible conflicts exists, mitigation will be discussed in the EIS. The estimates of the social and regional costs developed for each area (see Part II.B and Appendix G) include the costs of the potential effects of OCS oil and gas activities on other uses of the sea and seabed, including commercial fishing and recreation.

Item (E) concerning the interest of potential oil and gas producers, is addressed in Part III and Appendices B and D. The interest expressed in each planning area was considered in determining the timing and location of sales. It is important to note that the relative interest of energy firms can differ from the relative ranking of areas based on MMS hydrocarbon estimates which appears in Appendix F. This is important because it provides information for selecting the timing and location of sales on factors in addition to MMS

information regarding Item (F), laws, goals, and policies of affected States, can be found in Appendix C. This information has been reviewed to determine their implications for the planning of leasing activity. Appendix C also includes a table of approved coastal zone management plans. The EIS will contain a characterization of each plan.

As the court held in California v. Watt (1), the Secretary need not delete an area from the schedule solely because such activity may be inconsistent with State policies. The information found in Appendix C may also be useful in assessing of potential effects on the coastal zone as required by 18(a)(3).

Item (G) regarding relative environmental sensitivity and marine productivity is addressed in Part II.B.3 and in Appendix I. Professional judgments have been made of the relative environmental sensitivity and marine productivity of each OCS area and in addition of the adjacent coastal areas. These judgments were based on a detailed review of data on the environmental and marine resources in each area. Through its input to the social cost calculations, this analysis provides a partial basis for considering "an equitable sharing of developmental benefits and environmental risk" 18(a)(2)(B) and the balancing of factors called for by 18(a)(3).

Estimates of social costs found in Part II.B and Appendix G are, to the extent possible, consistent with and reflect the information on and judgments about relative environmental sensitivity and marine productivity. However, many aspects of environmental sensitivity and marine productivity cannot be quantified in dollar terms. Thus, in addressing the 18(a)(3) requirement, the judgments made about relative environmental sensitivity and marine productivity should therefore be reviewed together with the section on social and regional costs.

Item (H), environmental and predictive information, is reflected in Part II.B and is discussed further in Appendix H. It will also be addressed in the EIS.

In reviewing the July 1982 program, the court validated the Secretary's consideration of items (B) and (G) in determining the location of leasing. These items, together with other 18(a)(2) items, will be reviewed to determine if any planning areas warrant exclusion from the schedule.

In reviewing the timing of leasing in the July 1982 program, the court validated the Secretary's consideration of the environmental and coastal zone elements of section 18. These factors will also be considered in Part II.B, C, and D, and Appendices B, C, G, H, and I. They will also appear in the EIS.

4. 18(a)(3)

a. Requirement

"The Secretary shall select the timing and location of leasing, to the maximum extent practicable, so as to obtain a proper balance between the potential for environmental damage, the potential for discovery of oil and gas, and the potential for adverse impact on the coastal zone."

b. Compliance

This requirement is addressed in Part II.B, C, and D and Appendices E, F, G, H, and I. Those sections present information on social and regional costs, including environmental damage and adverse effects on the coastal zone, expected oil and gas resources, and net economic values by planning area. This information is used to calculate the net social value of each area. Relevant qualitative factors not reflected in these calculations are assessed in Part II.B.3, Part II.C, and Appendices H and I and will be addressed in the EIS. These factors are reviewed together with the net social value calculations in formulating a leasing program.

The court in California v. Wart (II) endorsed the general interpretation of the balancing required by 18(a)(3) which was used in formulating the July 1982 program. This interpretation was that an area should be included if the benefits of leasing are expected to exceed the costs and that the most valuable areas should be offered first. The court also ruled that the analysis of both section 18(a)(2) and 18(a)(3) factors could be on an area-by-area basis, and a schedule-by-schedule basis.

Planning area analyses appear in Part II. Schedule-by-schedule comparisons appear in the form of the discussion of the cost of the delay of leasing in Part II.B and Appendix F and in Part III.

The court also required that the damage from oil spills on fishing, tourism and other OCS-related enterprises be quantified. This has been done in the calculation of social and regional costs for each area and is described in Part II.B.2 and Appendix G. The calculation of the net economic value of OCS oil and gas production is explained in Part II.B.1 and Appendix F.

5. 18(a)(4)

a. Requirement

"Leasing activities shall be conducted so to assure receipt of fair market value for the lands leased and the rights conveyed by the Federal Government."

b. Compliance

Decisions on the leasing schedule are, for the most part, separable from decisions on bid evaluation procedures. However, the decision will be made on bid evaluation procedures contemporaneously with other decisions on the program so that means for assuring receipt of fair market value are clearly indicated as part of the Draft Proposed Program. A paper discussing the conceptual underpinnings of this requirement and of the general approaches considered in meeting it can be found in Appendix K.

6. 18(b)

a. Requirement

"The leasing program shall include estimates of the appropriations and staff required to--

(1) obtain resource information and any other information needed to prepare the leasing program required by this section;

(2) analyze and interpret the exploratory data and any other information which may be compiled under the authority of this Act;

(3) conduct environmental studies and prepare any environmental impact statement required in accordance with this Act and with section 102(2)(C) of the National Environmental Policy Act of 1969 (42 U.S.C. 4332(2)(C)); and

(4) supervise operations conducted pursuant to each lease in the manner necessary to assure due diligence in the exploration and development of the lease area and compliance with the requirements of applicable law and regulations, and with the terms of the lease."

b. Compliance

The decision on the Draft Proposed Program and on the alternatives to be analyzed in the EIS will be reviewed by MMS for estimates of appropriations and staff. These estimates will appear in the decision materials for the Proposed Final Program.

II. Excerpts from the OCS Lands Act Amendments of 1978.

TITLE I—FINDINGS AND PURPOSES WITH RESPECT TO MANAGING THE RESOURCES OF THE OUTER CONTINENTAL SHELF

FINDINGS

43 USC 1801.

SEC. 101. The Congress finds and declares that—

(1) the demand for energy in the United States is increasing and will continue to increase for the foreseeable future;

(2) domestic production of oil and gas has declined in recent years;

(3) the United States has become increasingly dependent upon imports of oil from foreign nations to meet domestic energy demand;

(4) increasing reliance on imported oil is not inevitable, but is rather subject to significant reduction by increasing the development of domestic sources of energy supply;

(5) consumption of natural gas in the United States has greatly exceeded additions to domestic reserves in recent years;

(6) technology is or can be made available which will allow significantly increased domestic production of oil and gas without undue harm or damage to the environment;

(7) the Outer Continental Shelf contains significant quantities of oil and natural gas and is a vital national resource reserve which must be carefully managed so as to realize fair value, to preserve and maintain competition, and to reflect the public interest;

(8) there presently exists a variety of technological, economic, environmental, administrative, and legal problems which tend to retard the development of the oil and natural gas reserves of the Outer Continental Shelf;

(9) environmental and safety regulations relating to activities on the Outer Continental Shelf should be reviewed in light of current technology and information;

(10) the development, processing, and distribution of the oil and gas resources of the Outer Continental Shelf, and the siting of related energy facilities, may cause adverse impacts on various States and local governments;

(11) policies, plans, and programs developed by States and local governments in response to activities on the Outer Continental Shelf cannot anticipate and ameliorate such adverse impacts unless such States, working in close cooperation with affected local governments, are provided with timely access to information regarding activities on the Outer Continental Shelf and an opportunity to review and comment on decisions relating to such activities;

(12) funds must be made available to pay for the prompt removal of any oil spilled or discharged as a result of activities on the Outer Continental Shelf and for any damages to public or private interests caused by such spills or discharges;

(13) because of the possible conflicts between exploitation of the oil and gas resources in the Outer Continental Shelf and other uses of the marine environment, including fish and shellfish growth and recovery, and recreational activity, the Federal Government must assume responsibility for the minimization or elimination of any conflict associated with such exploitation;

(14) the oil and gas resources of the Outer Continental Shelf are limited, nonrenewable resources which must be developed in a manner which takes into consideration the Nation's long-range energy needs and also assures adequate protection of the renewable resources of the Outer Continental Shelf which are a continuing and increasingly important source of food and protein to the Nation and the world; and

(15) funds must be made available to pay for damage to commercial fishing vessels and gear resulting from activities involving oil and gas exploration, development, and production on the Outer Continental Shelf.

PURPOSES

43 USC 1802

SEC. 102. The purposes of this Act are to—

(1) establish policies and procedures for managing the oil and natural gas resources of the Outer Continental Shelf which are intended to result in expedited exploration and development of the Outer Continental Shelf in order to achieve national economic and energy policy goals, assure national security, reduce dependence on foreign sources, and maintain a favorable balance of payments in world trade;

(2) preserve, protect, and develop oil and natural gas resources in the Outer Continental Shelf in a manner which is consistent with the need (A) to make such resources available to meet the Nation's energy needs as rapidly as possible, (B) to balance orderly energy resource development with protection of the human, marine, and coastal environments, (C) to insure the public a fair and equitable return on the resources of the Outer Continental Shelf, and (D) to preserve and maintain free enterprise competition;

(3) encourage development of new and improved technology for energy resource production which will eliminate or minimize risk of damage to the human, marine, and coastal environments;

(4) provide States, and through States, local governments, which are impacted by Outer Continental Shelf oil and gas exploration, development, and production with comprehensive assistance in order to anticipate and plan for such impact, and thereby to assure adequate protection of the human environment;

(5) assure that States, and through States, local governments, have timely access to information regarding activities on the Outer Continental Shelf, and opportunity to review and comment on decisions relating to such activities, in order to anticipate, ameliorate, and plan for the impacts of such activities;

(6) assure that States, and through States, local governments, which are directly affected by exploration, development, and production of oil and natural gas are provided an opportunity to participate in policy and planning decisions relating to management of the resources of the Outer Continental Shelf;

(7) minimize or eliminate conflicts between the exploration, development, and production of oil and natural gas, and the recovery of other resources such as fish and shellfish;

(8) establish an oilspill liability fund to pay for the prompt removal of any oil spilled or discharged as a result of activities on the Outer Continental Shelf and for any damages to public or private interests caused by such spills or discharges;

(9) insure that the extent of oil and natural gas resources of the Outer Continental Shelf is assessed at the earliest practicable time; and

(10) establish a fishermen's contingency fund to pay for damages to commercial fishing vessels and gear due to Outer Continental Shelf activities.

III. Excerpts from 30 CFR 256.

Subpart B—Oil and Gas Leasing Program

§ 256.14 Definitions.

As used in this subpart, the term—"Affected State" and "affected States" means Maine, New Hampshire, Massachusetts, Rhode Island, Connecticut, New York, New Jersey, Pennsylvania, Delaware, Maryland, Virginia, North Carolina, South Carolina, Georgia, Florida, Alabama, Mississippi, Louisiana, Texas, California, Oregon, Washington, and Alaska.

[44 FR 38276, June 29, 1979. Redesignated at 47 FR 47006, Oct. 22, 1982; 47 FR 50684, Nov. 9, 1982]

§ 256.16 Receipt and consideration of nominations; public notice and participation.

(a) During preparation of a proposed 5-year leasing program, the Secretary shall invite and consider suggestions and relevant information for such program from Governors of affected States, local government, industry, other Federal agencies, including the Attorney General in consultation with the Federal Trade Commission, and all interested parties, including the general public. This request for information shall be issued as a notice in the FEDERAL REGISTER. Local governments wishing to respond to such request shall first submit their responses to the Governor of the State in which the local government is located.

(b) The Secretary shall send letters to the Governors of the affected States requesting them to identify specific laws, goals, and policies which they believe should be considered by the Secretary in connection with the leasing program. The Secretary shall also request from the Secretary of Energy information on regional and national energy markets, on OCS production goals and on transportation networks.

[44 FR 38276, June 29, 1979. Redesignated at 47 FR 47006, Oct. 22, 1982; 47 FR 50684, Nov. 9, 1982]

§ 256.17 Review by State and local governments and other persons.

(a)(1) The Secretary shall prepare a proposed leasing program. At least 60 days prior to publication of the proposed program in the FEDERAL REGISTER, a copy of the draft of the proposed program shall be forwarded to the Governor of each affected State for comment. The Governor may solicit comments from local governments in his or her State which the Governor determines will be affected by the proposed program.

(2) The Secretary shall reply in writing to any comment on the draft of the proposed program from the Governor of an affected State which is received at least 15 days prior to the submission of the proposed program to the Congress and publication in the FEDERAL REGISTER. All such correspondence between the Secretary and Governor of such State shall accompany the proposed program when it is submitted to the Congress.

(b) The proposed leasing program shall be submitted to the Governors of the affected States for review and comment at the time it is submitted to the Congress and the Attorney General and published in the FEDERAL REGISTER. The Governor of an affected State shall, upon request from any local government affected by the program, submit a copy of the proposed program to such local government. Comments and recommendations on any aspect of the proposed program may be submitted by a State or local government or other persons to the Secretary within 90 days after the date of its publication in the FEDERAL REGISTER. Comments and recommendations from local governments shall be submitted first to the Governor of the State in which the local government is located.

(c) At least 60 days prior to approving the final leasing program and any later significant revision, the Secretary shall submit it to the President and the Congress, together with any comments. The Secretary shall indicate in such submission why any specific recommendation of the Attorney General or of a State or local government was not accepted.

[44 FR 38276, June 29, 1979, as amended at 47 FR 25970, June 16, 1982. Redesignated at 47 FR 47006, Oct. 22, 1982; 47 FR 50684, Nov. 9, 1982]

§ 256.19 Periodic consultation with interested parties.

The Secretary shall provide for periodic consultation with State and local governments, existing and potential oil and gas lessees and permittees, and representatives of other individuals or organizations engaged in any activity in or on the OCS, including those involved in fish and shellfish recovery, and recreational activities. This consultation shall take place primarily through appropriate public notice as described in §§ 256.16 and 256.17 and through the OCS Advisory Board and its committees, on a regional and national basis. Meetings of the OCS Advisory Board shall be held on specific issues as required by the Board's charter.

[44 FR 38276, June 29, 1979. Redesignated at 47 FR 47006, Oct. 22, 1982; 47 FR 50684, Nov. 9, 1982]

§ 256.20 Consideration of coastal zone management program.

In the development of the leasing program, consideration shall be given to the coastal zone management program being developed or administered by an affected coastal State under section 305 or 306 of the Coastal Zone Management Act of 1972 as amended, (16 U.S.C. 1454, 1455). Information concerning the relationship between a State's coastal zone management program and OCS oil and gas activity shall be requested from the Governors of the affected coastal States and from the Secretary of Commerce prior to the development of the proposed leasing program at the time information is requested under § 256.16 of this part.

[44 FR 38276, June 29, 1979. Redesignated at 47 FR 47006, Oct. 22, 1982; 47 FR 50684, Nov. 9, 1982]

STATE OF CALIFORNIA, Acting By and Through Governor Edmund G. BROWN, Jr., the California Coastal Commission, the California Air Resources Board, the California Resources Agency, and the California Department of Conservation, Petitioners,

v.

James G. WATT, Secretary of the Interior and the United States Department of the Interior, Respondents,

American Petroleum Institute, et al., Intervenors.

STATE OF ALASKA, Petitioner,

v.

James G. WATT, Secretary of the Interior and the United States Department of the Interior, Respondents,

American Petroleum Institute, et al., Intervenors.

NATURAL RESOURCES DEFENSE COUNCIL, INC., Sierra Club, Conservation Law Foundation of New England, Inc., and Friends of the Earth, Petitioners,

v.

James G. WATT, Secretary of the Interior and the United States Department of the Interior, Respondents,

American Petroleum Institute, et al., Intervenors.

NORTH SLOPE BOROUGH, Jacob Adams, Mayor of the North Slope Borough, and Lloyd Ahvakana, Petitioners,

v.

James G. WATT, Secretary of the Interior and the United States Department of the Interior, Respondents,

American Petroleum Institute, et al., Intervenors.

STATE OF CALIFORNIA, Acting By and Through Governor Edmund G. BROWN, Jr., and the California Coastal Commission, Petitioners,

v.

James G. WATT, Secretary of the Interior and the United States Department of the Interior, Respondents,

American Petroleum Institute, et al., Intervenors.

STATE OF ALASKA, Petitioner,

v.

James G. WATT, Secretary of the Interior and the United States Department of the Interior, Respondents,

American Petroleum Institute, et al., Intervenors.

NATURAL RESOURCES DEFENSE COUNCIL, INC., Sierra Club, Friends of the Earth, National Wildlife Federation, National Audubon Society, Conservation Law Foundation of New England, Inc. and Trustees for Alaska, Petitioners,

v.

James G. WATT, Secretary of the Interior and the United States Department of the Interior, Respondents,

American Petroleum Institute, et al., Intervenors.

NORTH SLOPE BOROUGH, Petitioner,

v.

James G. WATT, Secretary of the Interior and the United States Department of the Interior, Respondents,

American Petroleum Institute, et al., Intervenors.

CENALIULRITT, the Yukon-Kuskokwim Coastal Resource Service Area Board, Petitioner,

v.

James G. WATT, Secretary of the Interior and the United States Department of the Interior, Respondents,

American Petroleum Institute, et al., Intervenors.

STATE OF FLORIDA ex rel. Bob GRAHAM, Governor, and Jim Smith, Attorney General: State of Florida Department of Natural Resources: State of

Florida Department of Environmental Regulation, Petitioners,

v.

James G. WATT, Secretary of the Interior and the United States Department of the Interior, Respondents,

American Petroleum Institute, et al., Intervenors.

STATE OF WASHINGTON, Petitioner,

v.

James G. WATT, Secretary of the Interior and the United States Department of the Interior, Respondents,

American Petroleum Institute, et al., Intervenors.

CITY OF LOS ANGELES, Petitioner,

v.

James G. WATT, Secretary of the Interior and the United States Department of the Interior, Respondents,

American Petroleum Institute, et al., Intervenors.

STATE OF OREGON, Petitioner,

v.

James G. WATT, Secretary of the Interior and the United States Department of the Interior, Respondents,

American Petroleum Institute, et al., Intervenors.

STATE OF OREGON, Petitioner,

v.

James G. WATT, Secretary of the Interior and the United States Department of the Interior, Respondents.

Nos. 80-1894, 80-1897, 80-1935, 80-1991, 82-1822, 80-1823, 80-1824, 80-1825, 82-1826, 82-2081, 82-2085, 82-2097, 82-2102 and 82-2118.

United States Court of Appeals, District of Columbia Circuit.

Argued 23 May 1983.

Decided 5 July 1983.

After remand, 668 F.2d 1250, appeal was taken from Secretary of Interior's proposed five-year schedule of offshore oil and gas leasing activity. The Court of Appeals, Wilkey, Circuit Judge, held that: (1) Secretary complied with precision requirement of Outer Continental Shelf Lands Act; (2) process engaged in by Secretary to determine timing and location of offshore oil and gas leasing activity met obligations of Act; (3) Secretary based leasing program upon result of his consideration of factors set forth in Act; (4) Secretary's cost benefit analysis was reasonable; (5) program adopted by Secretary was sufficient to assure that fair-market value was received; (6) Secretary's evaluation of impacts on Oregon and Washington comported with requirements of Act; (7) environmental impact statement prepared for program adequately evaluated impact of oil spills on Washington and Oregon environment; and (8) regulation issued by Secretary in conformity with requirement of establishing procedures for consideration of coastal zone management program developed by states pursuant to Coastal Zone Management Act clearly met requirement of Outer Continental Shelf Lands Act.

Affirmed.

1. Public Lands ⇐108

Determinations of Secretary of Interior with respect to factual findings or policy judgments are entitled to more deference than Secretary's interpretation of statute.

2. Public Lands ⇐108

Jaundiced view which courts sometimes take of agency determination which remains largely the same after remand was not in order, where Secretary of Interior and administration had changed after remand.

3. Mines and Minerals ⇐5.1(1, 3)

Under Outer Continental Shelf Lands Act, Secretary of Interior must inform interested parties of areas which he is genuinely considering for leasing activity; if he is considering offering entire area in one lease, Secretary must include that as single

sale on the program; if, on the other hand, Secretary has already determined that area will be leased at two separate times, he cannot lump two together as one sale under five-year leasing program. Outer Continental Shelf Lands Act, § 18(a), as amended, 43 U.S.C.A. § 1344(a).

4. Mines and Minerals ⇐5.1(3)

Secretary of Interior properly designated entire planning areas as possible sales of offshore oil and gas leases, where, at time leasing program was adopted, Secretary knew only that leasing activity could occur in any portion of each planning area and indeed perhaps in all portions of any particular planning area. Outer Continental Shelf Lands Act, § 18(a), as amended, 43 U.S.C.A. § 1344(a).

5. Mines and Minerals ⇐5.1(1)

Since Secretary of Interior was considering offering oil and gas lease which included entire planning area, he was entitled, under Outer Continental Shelf Lands Act, to designate entire planning area as one proposed lease regardless of its size. Outer Continental Shelf Lands Act, § 18(a), as amended, 43 U.S.C.A. § 1344(a).

6. Mines and Minerals ⇐5.1(3)

It was not unreasonable for Secretary of Interior, and it was no violation of Outer Continental Shelf Lands Act, to seek input from industry before proceeding to exact designation of which tracts would be offered for sale of oil and gas leases. Outer Continental Shelf Lands Act, § 18(a), as amended, 43 U.S.C.A. § 1344(a).

7. Mines and Minerals ⇐5.1(9)

Secretary of Interior, on remand of proposed five-year schedule of offshore oil and gas leasing activity, complied with court's order that he change California sale designation, by dividing broad California planning area into two planning areas, Southern California and Central and Northern California. Outer Continental Shelf Lands Act, § 18(a), as amended, 43 U.S.C.A. § 1344(a).

8. Health and Environment ⇐25.7(8)
Mines and Minerals ⇐5.1(3)

Process engaged in by Secretary of Interior to determine timing and location of offshore oil and gas leasing activity met obligation of Outer Continental Shelf Lands Act to consider "an equitable sharing of developmental benefits and environmental risks among the various regions" and to consider "the relative environmental sensitivity and marine productivity of different areas of the Outer Continental Shelf." Outer Continental Shelf Lands Act, § 18(a)(2)(B, G), as amended, 43 U.S.C.A. § 1344(a)(2)(B, G).

9. Health and Environment ⇐25.7(8)
Mines and Minerals ⇐5.1(3)

Secretary of Interior based offshore oil and gas leasing program upon result of his consideration of factors set forth in Outer Continental Shelf Lands Act, by complying with requirement that he determine that none of the factors posed absolute or categorical impediment to leasing a particular area and by using information gathered in considering the factors when performing balancing analysis required by the Act. Outer Continental Shelf Lands Act, § 18(a)(2, 3), as amended, 43 U.S.C.A. § 1344(a)(2, 3).

10. Health and Environment ⇐25.7(8)

Cost benefit analysis utilized by Secretary of Interior in proposed five-year schedule of offshore oil and gas leasing, which revolved around calculation of each planning area's "net social value," which was calculated by subtracting external costs from net economic value, was reasonable. Outer Continental Shelf Lands Act, § 18(a)(3), as amended, 43 U.S.C.A. § 1344(a)(3).

11. Mines and Minerals ⇐5.1(1)

Proposed evaluation process, coupled with reasonable reliance by Secretary of Interior on integrity of competitive bid process, was sufficient to assure receipt of fair-market value for offshore oil and gas leases, as required by Outer Continental Shelf Lands Act. Outer Continental Shelf Lands Act, § 18(a)(4), as amended, 43 U.S.C.A. § 1344(a)(4).

12. Health and Environment ⇐25.7(8)

Outer Continental Shelf Lands Act did not require Secretary of Interior to fully evaluate area in which he had already determined that no oil and gas leasing would occur. Outer Continental Shelf Lands Act, § 18(a), as amended, 43 U.S.C.A. § 1344(a).

13. Health and Environment ⇐25.7(8)

Evaluation by Secretary of Interior of effect of oil spills from Alaska and Northern California on Washington and Oregon comported with requirements of Outer Continental Shelf Lands Act. Outer Continental Shelf Lands Act, § 18(a), as amended, 43 U.S.C.A. § 1344(a).

14. Health and Environment ⇐25.10(6)

Environmental impact statement prepared for five-year program of offshore oil and gas leasing activity adequately evaluated impact of oil spills on Washington and Oregon environment. National Environmental Policy Act of 1968, § 102, 42 U.S.C.A. § 4332.

15. Health and Environment ⇐25.7(8)

Regulation issued by Secretary of Interior in conformity with requirement of establishing procedures for consideration of coastal zone management program developed by states pursuant to Coastal Zone Management Act clearly met requirement of Outer Continental Shelf Lands Act, and Secretary was not required to outline when he would make consistency determination under Coastal Zone Management Act. Outer Continental Shelf Lands Act, § 18(f)(5), as amended, 43 U.S.C.A. § 1344(f)(5); Marine Resource and Engineering Development Act of 1966, § 307, as amended, 16 U.S.C.A. § 1456.

On Petition for Review of an Order of the United States Department of the Interior.

John A. Saurenman, Deputy Atty. Gen., State of Cal., with whom Theodora Berger, Deputy Atty. Gen., State of Cal., were on brief for petitioners in Nos. 80-1894 and 82-1822.

Lauri J. Adams, Asst. Atty. Gen., State of Alaska, with whom Wilson Condon, Atty. Gen., State of Alaska, and Jonathan K. Tillinghast, Sp. Asst. Atty. Gen., State of Alaska, were on brief for petitioner in Nos. 80-1897 and 82-1823.

James M. Hecker, with whom Bruce J. Terris and Edward H. Comer, were on brief for petitioners in Nos. 80-1991 and 82-1825.

Sarah Chasis, with whom Jane Bloom, were on brief for petitioners in Nos. 80-1935 and 82-1824.

Norman A. Cohen, was on brief for petitioner in Nos. 82-2102 and 82-2118.

Kay Kiner James, Asst. Atty. Gen., State of Oregon, with whom William F. Gary, Sol. Gen., State of Or., were on brief for petitioner in No. 82-2085.

Charles B. Roe, Jr., Senior Asst. Atty. Gen., State of Wash., was on brief for petitioner in No. 82-2085.

Charles H. Martin, and Bruce Barkett, Attys., State of Florida, entered appearances for petitioner in No. 82-2081.

Jan Chatten-Brown, Senior Asst. City Atty., entered an appearance for petitioner in No. 82-2097.

Wells D. Burgess, Atty., U.S. Dept. of Justice, for respondents. Carol E. Dinkins, Asst. Atty. Gen., U.S. Dept. of Justice, was on brief for respondents.

E. Edward Bruce, with whom Bobby R. Burchfield, Constance J. Chatwood, Stark Ritchie and David T. Deal, were on the brief for intervenors.

Stephen M. Leonard, Asst. Atty. Gen., Commonwealth of Massachusetts, was on the brief for amicus curiae, Francis X. Bellotti, Atty. Gen., Commonwealth of Massachusetts, urging remand to the Secretary for reconsideration.

Michael Axline and Richard Hildreth, were on brief for amicus curiae, Oregon Shores Conservation Coalition, Inc., et al., urging remand to the Secretary for reconsideration in Nos. 82-2102, 82-2118, 82-2081, 82-2085 and 82-2097. John E. Romne

also entered an appearance for Amicus Curiae in No. 82-2102.

Before ROBINSON, Chief Judge, WILKEY and SCALIA, Circuit Judges.

Opinion for the Court filed by Circuit Judge WILKEY.

WILKEY, Circuit Judge:

This case requires the court, for the second time, to review the Secretary of Interior's proposed five year schedule of offshore oil and gas leasing activity. After our first review we remanded the program to the Secretary to correct defects resulting largely from the Secretary's erroneous interpretation of the relevant statute. This time we uphold the program, concluding that the earlier errors have been rectified and that the overall program now conforms with the requirements of the Outer Continental Shelf Lands Act.

I. Background

A. *The Statutory Scheme*

The Outer Continental Shelf Lands Act,[1] enacted in 1953, authorizes the Secretary of the Interior to grant leases for the development of oil and gas deposits contained in the shelf's submerged lands. Congress amended[2] the Act in 1978[3] in order to "promote the swift, orderly and efficient exploration of our almost untapped domestic oil and gas resources in the Outer Continental Shelf."[4] The 1978 amendments outlined a five step process for achieving this expeditious but orderly development. The first step is the adoption of a five-year leasing program which contains a proposed schedule of lease sales.[5] This is followed by sale of the leases,[6] exploration,[7] development and production,[8] and ultimately, sale of the recovered minerals.[9] The five step process is "pyramidic in structure, proceeding from broad-based planning to an increasingly narrower focus as actual development grows more imminent."[10] Additional study and consideration is required before each succeeding step is taken. Thus, while an area excluded from the leasing program cannot be leased, explored, or developed, an area included in the program may be excluded at a latter stage. The present challenge is to the first, and thus broadest-based, portion of the process—the five-year leasing program adopted pursuant to section 18.

Section 18 requires the Secretary to prepare, maintain, and periodically revise a five-year leasing program consisting of a "schedule of proposed lease sales, indicating, as precisely as possible, the size, timing and location of leasing activity."[11] The program must be prepared and maintained in accordance with four principles. Since these are basic to the Secretary's action, the petitioners' challenge, and our own analysis, we set them forth textually in full:

> (1) Management of the outer Continental Shelf shall be conducted in a manner which considers economic, social, and environmental values of the renewable and nonrenewable resources contained in the outer Continental Shelf, and the potential impact of oil and gas exploration on other resource values of the outer Continental Shelf and the marine, coastal, and human environments.

1. 43 U.S.C. §§ 1331-1356 (1976 & Supp. V 1981).

2. Events leading up to the 1978 amendment are outlined in *California v. Watt*, 668 F.2d 1290, 1295-96 (D.C.Cir.1981) (per curiam).

3. Pub.L. No. 95-372, Title II, 92 Stat. 632 (1978).

4. H.R.Rep. No. 95-590, 95th Cong., 1st Sess. 53 (1977), U.S.Code Cong. & Admin.News 1978, p. 1450, 1460.

5. 43 U.S.C. § 1344 (Supp. V 1981).

6. *Id.*, § 1337.

7. *Id.*, § 1340.

8. *Id.*, § 1351.

9. *Id.*, § 1353.

10. *California v. Watt*, 668 F.2d 1290, 1297 (D.C.Cir.1981).

11. 43 U.S.C. § 1344(a) (Supp. V 1981).

> (2) Timing and location of exploration, development, and production of oil and gas among the oil- and gas-bearing physiographic regions of the outer Continental Shelf shall be based on a consideration of—
>
> (A) existing information concerning the geographical, geological, and ecological characteristics of such regions;
>
> (B) an equitable sharing of developmental benefits and environmental risks among the various regions;
>
> (C) the location of such regions with respect to, and the relative needs of, regional and national energy markets;
>
> (D) the location of such regions with respect to other uses of the sea and seabed, including fisheries, navigation, existing or proposed sealanes, potential sites of deepwater ports, and other anticipated uses of the resources and space of the outer Continental Shelf;
>
> (E) the interest of potential oil and gas producers in the development of oil and gas resources as indicated by exploration or nomination;
>
> (F) laws, goals, and policies of affected States which have been specifically identified by the Governors of such States as relevant matters for the Secretary's consideration;
>
> (G) the relative environmental sensitivity and marine productivity of different areas of the outer Continental Shelf; and
>
> (H) relevant environmental and predictive information for different areas of the outer Continental Shelf.
>
> (3) The Secretary shall select the timing and location of leasing, to the maximum extent practicable, so as to obtain a proper balance between the potential for environmental damage, the potential for the discovery of oil and gas, and the potential for adverse impact on the coastal zone.
>
> (4) Leasing activities shall be conducted to assure receipt of fair market value for the lands leased and the rights conveyed by the Federal Government.[12]

The present litigation focuses on the Secretary's compliance with these principles in preparing and adopting the latest five-year leasing program.

B. *The Present Litigation*

On 16 June 1980 the Secretary adopted a five-year leasing program containing a schedule of proposed lease sales for the years 1980-1985. This program, largely prepared by Secretary Andrus, was challenged in this court by various state and local governments and several environmental groups. In an opinion filed 6 October 1981,[13] this court found "much of the Secretary's program is free of infirmity,"[14] but noted that the existence of several deficiencies required it to remand the program to Secretary Watt for revision in accordance with its opinion. Specifically, the court held that the Secretary erred in failing

> (1) to identify Sales 73 and 80 with greater specificity, (2) to consider the need to share developmental benefits and environmental risks among the various OCS regions, (3) to consider the relative environmental sensitivity and marine productivity of different areas of the OCS, (4) to base timing and location of leasing on some of the standards of section 18(a)(2), (5) to strike a proper balance incorporating environmental and coastal zone factors and not simply administrative need and economic factors such as potential oil and gas recovery, (6) to quantify environmental costs to the extent they are quantifiable, and (7) to adequately explain his determination of net economic value, particularly the economic effects of delaying leasing.[15]

The court retained jurisdiction over the case and directed that lease sales scheduled to

12. *Id.*

13. *California v. Watt*, 668 F.2d 1290 (D.C.Cir. 1981) (per curiam) (*Watt I*).

14. *Id.* at 1325.

15. *Id.*

occur during the remand period be allowed to proceed.[16]

At the time Secretary Watt was in the process of revising and reapproving the program pursuant to section 18(e).[17] On 19 January 1982 the court issued an order in which it adopted the Secretary's position that he could meet the court's remand in the course of the revision and approved the Secretary's proposed timetable for completing the revision. On 21 July 1982 the Secretary approved the final five-year leasing program for the years 1982–1987. Petitioners in Nos. 82-1822, 82-1823, 82-1824, 82-1825, 82-1826, 82-2081, 82-2085, 82-2097, 82-2102, and 82-2118 challenged various aspects of that plan. Those petitions were consolidated with the earlier petitions over which this court retained jurisdiction.[18]

Petitioners launch a multi-pronged attack on the new five year program. They contend that (1) the program fails to indicate the size and location of leasing activity "as precisely as possible" as required by section 18(a); (2) the Secretary failed to give adequate consideration to, or base the program on, the environmental factors listed in 18(a)(2); (3) the Secretary violated section 18(a)(3) by making arbitrary assumptions and using incorrect methodology to ascertain the costs and benefits of leasing; (4) the program violates section 18(a)(4) because it fails to assure receipt of fair market value; (5) the Secretary failed to consider the environmental impact of the leasing program on Oregon and Washington causing him to violate section 18(a)(1), (2), and (3) of the OCLSA and section 102 of the National Environmental Policy Act;[19] and (6) the program violates section 18(f)(5) by failing to outline when the Secretary will make consistency determinations under section 307(c)(1) of the Coastal Zone Management Act.[20] We reject each of these arguments, concluding that the program under review meets the statutory guidelines laid down by Congress.

II. Standard of Review

At the outset it is important to note the difference between the nature of the challenges presented in this case and the challenges presented in *Watt I*. In *Watt I* the court noted that the five year program is based on three types of determinations: (1) the Secretary's factual findings, (2) the Secretary's policy judgments, and (3) the Secretary's legal interpretations. The court set out the standard for reviewing each of these types of determinations, stating that review of the first two types of determinations is quite deferential.

> When reviewing findings as ascertainable fact made by the Secretary, the substantial evidence test guides our inquiry. When reviewing the policy judgments made by the Secretary, including those predictive and difficult judgmental calls the Secretary is called upon to make, we will subject them to searching scrutiny to ensure that they are neither arbitrary nor irrational—in other words, we must determine whether "the decision [was] based on a consideration of the relevant factors and whether there has been a clear error of judgment."[21]

16. *Id* at 1326.

17. 43 U.S.C. § 1344(e) (Supp. V 1981). Section 18(e) directs the Secretary to review the leasing program annually and authorizes him to revise and reapprove the program "at any time."

18. Petitioners in the consolidated cases include the States of California, Alaska, Florida, Washington and Oregon, the Natural Resources Defense Council, Inc., the Sierra Club, the Conservation Law Foundation of New England, Inc., Trustees for Alaska, the Friends of the Earth, National Wildlife Federation, the National Audubon Society, the North Slope Borough and Cenaliuint (the Yukon-Kuskowim Coastal Resource Service Area Board). The Commonwealth of Massachusetts, the Oregon Shores Conservation Coalition, the Oregon Environmental Council, and the Oregon Wilderness Coalition filed as amicus curiae in support of petitioners' position.

19. 42 U.S.C. § 4332 (1976).

20. 16 U.S.C. § 1456(c)(1) (1976).

21. *Watt I*, 668 F.2d at 1302 (quoting in part *Citizens to Preserve Overton Park, Inc. v. Volpe*, 401 U.S. 402, 416, 91 S.Ct. 814, 824, 28 L.Ed.2d 136 (1971)).

The Secretary's interpretation of the statute, on the other hand, while entitled to some deference, is reviewed under a stricter standard, the court observed, because "the interpretation of statutes is a matter which ultimately lies in the province of the judiciary."[22]

[1] The distinction between review of factual findings and policy judgments and review of legal interpretations is important in this case because the majority of the defects noted in *Watt I* concerned the previous Secretary's erroneous interpretation of the statute.[23] The Secretary had misread the statute and, as a result, failed to perform the requisite analysis. On the other hand, with only a few exceptions, the challenges advanced by petitioners in this case concern the *adequacy* of the Secretary's analysis. They question the factual findings or policy judgments at the base of the Secretary's conclusions. These are matters on which the Secretary is entitled to greater deference. Thus, overall, the Secretary's determinations with respect to the matters being challenged in the present case are entitled to more deference than those which were struck down in *Watt I*.

[2] It is also important to note that the suspicion which sometimes arises when an agency reaches the same result after remand does not apply in the present context. This is not a case in which the agency had an incentive to defend its prior actions. The original five year plan was formulated by Secretary Andrus during the Carter Administration. On remand Secretary Watt, a member of the Reagan Administration, took a hard look at the program, and came up with a program resembling the earlier one in many respects. Secretary Watt had no incentive to defend the actions of Secretary Andrus unless he thought that they were correct. Thus, to the extent that the present program imitates the prior program it is not a reflective defensive gesture, but the result of an original appraisal. Therefore, the jaundiced view which courts sometimes take of an agency determination which remains largely the same after remand is not in order in the present case.

Keeping these two points in mind we turn to an analysis of each of the main contentions raised by petitioners, concluding that none of them undermines the validity of the five year program.

III. Precise Indication of the Size and Location of Leasing Activity

Section 18(a) directs the Secretary to prepare a leasing program which consists "of a schedule of proposed lease sales indicating, *as precisely as possible, the size, timing, and location of leasing activity*."[24] In *Watt I* the court did not "attempt to define ... the degree of exactitude compelled by section 18(a),"[25] because the Secretary conceded that greater specificity was possible, and, in fact, had employed greater specificity in designating other proposed sales scheduled for the waters off California.[26]

[3] However, the court recognized that in requiring the Secretary to specify the location of leasing activity "as precisely as possible," section 18 "implicitly recognizes that absolute precision is unobtainable at the program stage."[27] The purpose of the precision requirement is to notify interested parties of the areas on which leasing activi-

22. *Id* at 1303 (footnote omitted).

23. For example, the Secretary's primary error with respect to the evaluation required by section 18(a)(2) was that he mistakenly felt that the statute did not require him to consider fully all of the factors at the program level. *See id* at 1305–07. Similarly, the Secretary's analysis under section 18(a)(2)(B) was flawed mainly because the Secretary "interpreted the term 'environmental risk' contrary to the plain meaning of the statute." *Id* at 1308. Finally, the primary deficiency in the Secretary's section 18(a)(3) analysis was his failure to "consider and factor in all aspects of section 18(a)(2)," *id* at 1318, a defect directly attributable to the Secretary's misinterpretation of section 18(a)(2).

24. 43 U.S.C. § 1344(a) (Supp. V 1981) (emphasis added).

25. *Watt I*, 668 F.2d at 1304.

26. *Id*.

27. *Id*.

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ty will occur. Since the Secretary does not know exactly which areas will be leased, he is required only to specify "as precisely as possible," or, to put it another way, to reveal his full intentions at that time. He must inform interested parties of the areas which he is genuinely considering for leasing activity. If he is considering offering an entire area in one lease, the Secretary must include that as a single sale on the program. If, on the other hand, the Secretary has already determined that an area will be leased at two separate times he cannot lump the two together as one sale under the five-year leasing program. The Secretary, acting on his own geological survey data, designates planning areas as part of a five-year leasing program, which he will make more specific after further data in response to his call comes in. This common-sense interpretation of section 18(a) repudiates petitioners' main challenge to the manner in which the Secretary complied with the precision requirement.

[4] Petitioners contend that the program is insufficiently precise because each entire planning area is scheduled as one lease sale even though the Secretary has indicated that it is likely that only a portion of each area will actually be leased.[28] However, this argument misses the mark because, although the Secretary concedes that it is likely that only a portion of any particular planning area will be leased, he is unable at this time to determine which portions will or will not be leased. Section 18(a) requires the Secretary to designate areas of leasing activity only "as precisely as present information supports."[29] At the time the leasing program was adopted the Secretary knew only that leasing activity could occur in any portion of each planning area and indeed perhaps in all portions of any particular planning area. On the basis of that information the Secretary properly designated entire planning areas as possible lease sales.

Petitioners argue that the Secretary cannot defer beyond the program stage the decision of which areas to lease, apparently concluding that the Secretary must designate at the program stage which tracts will actually be leased. This argument ignores the structure of section 18(a). Section 18(a) is, as noted above, pyramidic in structure. Greater specificity is anticipated at each stage. Before an area is actually put up for sale, other steps must be taken, including an evaluation of the potential environmental and coastal zone effects under the National Environmental Policy Act and the Coastal Zone Management Act and state concerns under section 19 of the Outer Continental Shelf Land Act.[30] Doubtless, these evaluations, when considered in conjunction with the expressed interest of the industry and certain portions of the planning area, may result in a paring down of the size of the tracts actually offered for lease. However, at this point the Secretary intends to offer the entire area as one sale. He has thus indicated as precisely as present information supports the size and location of areas which will be offered for leasing activity.

[5] Petitioners attack the precision of the leasing program in three other respects. These attacks are also unavailing. Petitioners first contend that the Secretary has violated section 18(a) because the size of the planning areas designated on the proposed lease sale schedule are vastly larger than under the Andrus program.[31] However, section 18(a) does not require the Secretary to limit the size of a planning area to any specific acreage. It only requires the Secretary to indicate as precisely as possible the size of the areas on which leasing activity

28. Brief for Petitioners' States of California, State of Alaska, Natural Resources Defense Council, North Slope Borough, and Cenaliulrit at 36–37 [hereinafter referred to as California Brief]

29. *Watt I*, 668 F.2d at 1304.

30. 43 U.S.C. § 1345 (Supp. V 1981).

31. California Brief at 33–34. Petitioners note that the largest offering in the history of the offshore leasing program comprised 2.9 million acres, *id.* at 34 n. 1, while the present program includes one planning area of 133 million acres.

will occur. Since the Secretary is considering offering a lease which includes the entire planning area, he can designate the entire planning area as one proposed lease regardless of its size.

Second, petitioners claim that the Secretary has violated section 18(a) by unlawfully delegating to the members of the oil industry the designation of the areas which will actually be leased.[32] This is in reality a challenge to the leasing procedure which Secretary Watt adopted to implement the later stages of the offshore oil development program. Secretary Watt determined that, in light of the dismal record of exploration on the outer continental shelf, a new procedure was needed to enhance the possibility of major oil and gas finds. Thus, a new procedure was adopted. Under the new procedure the five year program sets out entire planning areas which will be considered for leasing. Prior to the call for information, one of the early steps in the new pre-sale process, the Department of Interior will identify the portions of the planning area which it believes have potential for discovery of commercial deposits of oil and gas. The identified portions will then be announced in the call. With the issuance of the call for information, the entire planning area will be open for consideration and the call will request information about the entire area. In response to the call, industry, states and other parties may suggest further areas of potential interest within or beyond those identified by the department but within the planning area. Following the call, states and others will also have an opportunity to comment on areas or topics of concern which should be considered in the planning for the lease sale. Using the responses to the call and other available data, the Secretary will approve the areas to be proposed for leasing. These areas will be analyzed in the sale-specific environmental impact statement. The proposed notice of sale will then include the defined area.

[6] Petitioners' argument that the Secretary has unlawfully delegated the identification of tracts for sale to the oil industry is in reality a challenge to this new procedure adopted by the Secretary, but we reject that attack. It is not unreasonable for the Secretary to seek input from the industry before proceeding to the exact designation of which tracts will be offered for sale. Indeed, in light of the pyramidic structure of the statute it would be surprising if the Secretary did not at least consider the possibility of narrowing down the size of the proposed lease sales, and input from industry is one factor which can reasonably be considered when that decision is made.

[7] Finally, we note that the Secretary complied with this court's order in *Watt I* that he change the California sale designation. In the latest program the broad California planning area is divided into two planning areas, Southern California and Central and Northern California.[33] In addition, several other changes were made which resulted in greater specificity. For example, the designation of sales 90 and 96, previously identified as Atlantic, were changed to South Atlantic and North Atlantic, respectively. Sale 100, in South Alaska, was divided into three smaller sales. And the North Atlantic planning area was restored to its prior status as two planning areas.[34] We therefore find no merit in petitioners' contention that the present five year program is less precise than the program reviewed by this court in *Watt I*.

32. California Brief at 39–40.

33. We also reject petitioners' contention that the Secretary was required to separate the Central and Northern California lease sale into two distinct sales. Petitioners argue that the Secretary had, in an earlier sale, divided the area into two sales and that accordingly a more precise offer was possible. However, the Secretary has never divided the Central and Northern area into two planning areas. What petitioners refer to is the Secretary's decision to delete four basins from a sale in the area to permit further review. Respondents' Brief at 28. This in no way indicates that there will be two sales there in the *future*. The Secretary did not limit himself to such a course by separating a portion of the area for further consideration.

34. Respondents' Brief at 19–20.

Accordingly, we hold that the Secretary has complied with the precision requirement of section 18(a).

IV. Compliance With Section 18(a)(2)

Section 18(a)(2) directs the Secretary to prepare the five-year leasing program consistent with the principle that "timing and location of exploration, development, and production of oil and gas among the oil- and gas-bearing physiographic regions of the outer continental shelf shall be based on a consideration of [eight enumerated factors]."[35] In *Watt I* the court rejected the Secretary's argument that he did not need to consider each of these eight factors at the program level.[36] The court held that section 18(a)(2) imposed a two-fold duty on the Secretary. First, "the Secretary [must] consider all factors listed in section 18(a)(2) in developing the leasing program."[37] Second, he "must base the leasing program upon the result of his consideration of these factors."[38]

[8] In an effort to comply with this dual obligation the Secretary, on remand, engaged in a six-step process to determine the timing and location of the leasing activity. First, he reviewed the results of a comparative analysis of planning areas prepared by the Interior staff and examined the conclusions which could be drawn from that analysis. All of the factors included under section 18(a)(2) which in the view of the Interior staff were subject to quantification were incorporated in this comparative analysis. Second, the Secretary considered the extensive comments received on the comparative analysis. Third, using the results of the analysis and the comments, initial conclusions were reached about the location and timing of the leasing activity, basing priority on a calculation of net social value for each planning area. Fourth, the section 18(a)(2) considerations which were not subjected to quantitative analysis or which were not incorporated in the net social value estimates, including more explicit consideration of the relative environmental sensitivity and marine productivity than was possible in the quantitative analysis, were reviewed in order to determine whether any of the initial conclusions should be modified. Fifth, after making the adjustments required by review of each of the factors listed in section 18(a)(2), the Secretary grouped the areas into three categories: those areas which should be leased on an annual basis, those which should be leased on a biennial basis, and those which should be leased only on a triennial basis. Finally, these groups were used to develop a schedule of proposed lease sales which became the five year program.[39] After reviewing the Secretary's analysis and methodology, we conclude that he has met the obligation imposed upon him by section 18(a)(2).

A. *Consideration of the Section 18(a)(2) Factors*

There is no dispute that Secretary Watt made an effort to consider all of the factors enumerated in section 18(a)(2). In this respect the present case is different from *Watt I* in which the Secretary erroneously interpreted the statute in a manner which relieved him of the responsibility of considering all of these factors at the program stage. Petitioners in the present case challenge the *adequacy* of the consideration, not the fact that the consideration was made. This lessens the level of our scrutiny.

Petitioners' challenge focuses on section 18(a)(2)(B), which requires that the Secretary consider "an equitable sharing of developmental benefits and environmental risks among the various regions,"[40] and section 18(a)(2)(G), which requires the Secretary to consider "the relative environmental sensitivity and marine productivity of different areas of the outer Continental Shelf."[41] We find the Secretary's analysis sufficient under both sections.

35. 43 U.S.C. § 1344(a)(2) (Supp. V 1981). The eight factors the Secretary must consider are listed at TAN 12.

36. *Watt I*, 668 F.2d at 1304-05.

37. *Id.* at 1305.

38. *Id.*

39. Joint Appendix (JA) at 2300-08.

40. 43 U.S.C. § 1344(a)(2)(B) (Supp. V 1981).

1. *Section 18(a)(2)(B).*

Petitioners contend that the Secretary's section 18(a)(2)(B) analysis is inadequate because it did not evaluate regional benefits and environmental risks on a planning area basis but rather on the basis of regions composed of states and groups of states.[42] Petitioners contend that this arbitrary definition of "region" flawed the section 18(a)(2)(B) analysis in two respects. First, the Secretary's consideration of states or aggregations of states masked the disproportionate share of risks borne by particular planning areas because it spread those risks out over a larger area. Second, the Secretary's method prevented him from considering section 18(a)(2)(B) in any meaningful manner because the results were not comparable with other section 18(a)(2) factors which were measured on a planning area basis. These attacks are meritless, however, because they do not accurately reflect what the Secretary did in considering section 18(a)(2)(B).

The Secretary specifically noted that "[e]stimates of both developmental benefits and environmental risks have been calculated *on a planning area basis*."[43] Thus, petitioners err when they contend that the Secretary evaluated the sharing of the developmental benefits and environmental risks only on a statewide basis.[44] The portion of the Secretary's analysis which petitioners attack is the Secretary's examination of the distribution of risks and benefits among the *people* who would be affected by oil and gas development. This was the second step the Secretary took under section 18(a)(2)(B). After noting that estimates of the benefits and risks had been calculated on a planning area basis, the Secretary observed that the manner in which those benefits would be shared by the population on shore "is not as obvious."[45] The Secretary recognized the common-sense proposition that the planning area itself, which is a portion of land lying under the ocean, does not benefit from development in any quantifiable sense. The Secretary thus *went on* to consider the relative distribution of risks and benefits among the people outside the planning areas who would be affected by oil and gas development in the various regions. He therefore *went beyond* what was required by the statute. The selection of these coastal regions was not, as petitioners claim, an arbitrary aggregation of planning areas into states or groups of states, but a legitimate attempt by the Secretary to consider on a quantified, reasonable basis, the distribution of benefits and risks from leasing in the planning areas among the coastal populations likely to be impacted by the development. This additional evaluation was made on a state by state basis since it is the state government which has the most prominent role in representing these people under the Outer Continental Shelf Lands Act.[46] We refuse to penalize the Secretary for going beyond what the statute requires.

2. *Section 18(a)(2)(G).*

Petitioners contend that the Secretary's 18(a)(2)(G) analysis is inadequate because the Secretary limited his consideration of relative environmental sensitivity and ma-

41. 43 U.S.C. § 1344(a)(2)(G) (Supp. V 1981).

42. California Brief at 115.

43. JA at 1278 (emphasis added).

44. The fact that the Secretary analyzed each *planning area* under § 18(a)(2)(B) is further evidenced by petitioners Washington and Oregon's argument that they were harmed because "the Secretary chose ... to consider the section 18(a)(2) factors only as they applied to the Department of Interior's designated 'planning areas.'" Brief for Petitioners Washington and Oregon at 5. *See also id.* at 20. Thus, different groups of petitioners attack the Secretary's § 18(a)(2) analysis on contradictory grounds. Both attacks are misplaced, however, because as noted in text the Secretary analyzed the section 18(a)(2) factors on *both* a planning-area and state-wide basis.

45. JA at 1278.

46. *See, e.g.*, 43 U.S.C. §§ 1344(a)(2)(F), (c), (f), 1345 (Supp. V 1981).

rine productivity exclusively to the impact from major oil spills. Petitioners claim that the Secretary's failure to consider other important types of impacts such as direct disturbance from support operations, offshore platform installment and operations, intentional discharges of drilling muds, cuttings, and produced waters from drilling operations, and chronic, small discharges of oil into the environment, was arbitrary. Thus, they argue, the Secretary's section 18(a)(2)(G) analysis was inadequate. However, we find this argument unpersuasive.

In *Watt I* this court noted that "[t]he statute provides no method by which environmental sensitivity and marine productivity are to be measured."[47] The statute requires only that the Secretary "make a good faith determination of the relative environmental sensitivity and marine productivity of the various regions based upon the best 'existing information' available to him."[48] The Secretary was therefore free to chose any methodology "so long as it is not irrational."[49] He has met this requirement.

The Secretary admitted that "[a] number of factors could be considered in ranking the environmental sensitivity of the OCS planning areas.... The sensitivity of those resources to the various aspects of OCS development, such as oil spills, structure placement, discharges and air emissions could also be considered."[50] However, he decided to base the relative environmental sensitivity rankings on the sensitivity of the various coastal and marine habitats to oil spills only and explained his reasons for doing so.

> [C]onsideration of habitat sensitivity was confined to the sensitivity to oil spills because spill effects are considered by many experts to be the greatest measurable biological effect of OCS development. Furthermore, some non-spill effects are localized and highly dependent on site-specific factors, and therefore have limited value for comparing entire planning areas. Finally, sensitivity to some environmental effects of OCS development is almost impossible to evaluate without considering the expected level of OCS activities—*i.e.*, it is difficult to establish a consensus definition of sensitivity.[51]

In essence the Secretary explained that oil spills were the greatest measurable effect on the environment and that other factors could not adequately be considered on the basis of available evidence. Since section 18(a)(2)(G) requires a comparative analysis,[52] the Secretary reasonably limited his consideration to the impact having the largest and most wide-spread effect on the environment. The relative environmental sensitivity and marine productivity can rationally be evaluated on that basis. It is important to remember that the program stage is the most general stage of the offshore leasing process. Consideration of specific environmental impacts on an area-by-area basis can be made as the program moves to the leasing, exploration, and development stages.

Petitioners also attack the Secretary's section 18(a)(2)(G) methodology in a different manner. The Secretary determined that the relative environmental sensitivity and marine productivity analysis could be performed by dividing each area into various coastal and marine habitats. Thus, in each area the coastal habitats were divided into beaches (including barrier islands), wetlands (including marshes and tundra), rocky shores (including cliffs), and lagoons (Alaska only).[53] The marine habitats in

47. *Watt I*, 668 F.2d at 1311.

48. *Id.* at 1313.

49. *Id.* at 1320.

50. JA at 1256.

51. *Id.*

52. Under section 18(a)(2)(G), the Secretary must consider the "*relative* environmental sensitivity and marine productivity of different areas." (emphasis added).

53. JA at 1257.

each area were divided into aquatic beds, submarine canyons, reefs and hard bottoms.[54] Petitioners contend that these classifications are not comprehensive, that major fish spawning, nursery, and feeding habitats are habitats which the Secretary did not consider in his study, and that the Secretary's failure to include these important habitat types and his selection of habitats for analysis on no articulated rationale violates this court's order in *Watt I*.[55] Again, however, petitioners' argument ignores important portions of the Secretary's decision.

The Secretary stated that he examined environmental sensitivity on a habitat basis because this allowed "all OCS areas to be analyzed according to common factors, avoiding the difficulty of weighing and comparing very different resources in different planning areas."[56] He explained his failure to consider some of the habitat types urged by petitioners, noting that such a procedure "would result in overlap—for example, wetlands often act as nursery grounds."[57] The Secretary therefore evaluated the relative environmental sensitivity and marine productivity of the various areas on a basis which he reasonably determined would result in the most reliable comparison. While it is possible to argue that there may have been a better methodology for evaluating these factors, we are unable to conclude that the Secretary's choice was irrational. Accordingly, his consideration of the factors outlined in section 18(a)(2)(G) was adequate.[58]

B. *Basing the Leasing Program on the Section 18(a)(2) Factors*

[9] As noted above, the Secretary must not only consider the section 18(a)(2) factors, he must "base the leasing program upon the result of his consideration of these factors."[59] This requires the Secretary to use the section 18(a)(2) analysis in two ways. First, the Secretary must determine that none of the section 18(a)(2) factors pose an "absolute or categorical impediment to leasing a particular area."[60] Second, the Secretary must use the information gathered in considering the section 18(a)(2) factors when performing the balancing analysis required by section 18(a)(3).[61] We conclude that the Secretary has complied with these requirements.

Petitioners advance three arguments in support of their contention that the Secretary has not based the leasing program on a consideration of the section 18(a)(2) factors. The first two are easily disposed of. The Petitioners first contend that the program could not have been based on a consideration of the section 18(a)(2) factors since that consideration was inadequate. Since we have already determined that the Secretary's consideration of all the section 18(a)(2) factors was in fact adequate there is no merit to this argument. Petitioners next contend that the Secretary unlawfully refused to adjust the timing of the various lease sales to reflect the results of his consideration of the section 18(a)(2) factors. This argument is also meritless.

Contrary to petitioners' implication, the Secretary did make adjustments after con-

54. *Id.*

55. California Brief at 131.

56. JA at 1256.

57. *Id.*

58. We also reject petitioners' contention that the Secretary erred in considering safety considerations and mitigation measures in deciding whether to alter the leasing schedule in response to his section 18(a)(2)(G) analysis. California Brief at 146–58. As we noted in *Watt I*, "the potential for environmental harm cannot be adequately considered and weighed without a like examination of the potential to mitigate such harm." 668 F.2d at 1317.

59. *Watt I*, 668 F.2d at 1305.

60. *Id.* at 1313.

61. *Id.* at 1315 n. 117. Thus, in *Watt I* the Secretary's primary shortcoming with respect to section 18(a)(3) was his "failure to consider and factor in all aspects of section 18(a)(2). This omission precluded him from meeting the requirement of section 18(a)(3) to obtain a proper balance to the maximum extent practicable." *Id.* at 1318.

sidering each of the section 18(a)(2) factors. For example, as a result of his section 18(a)(2)(B) analysis, the Secretary adjusted the schedule to accommodate the views of the State of Alaska. At the time of the decision on the tentative proposed final leasing program it was decided to delete sale number 75—North Aleutian Basin—and to delay leasing in Hope Basin for two years.[62] The section 18(a)(2)(B) analysis also resulted in changes to planning areas in the Gulf of Mexico. Two sales were eliminated (103 and 106) in the Eastern Gulf of Mexico, a frontier area with the lowest social values among the Gulf areas. The two remaining proposed sales in that area (sales 79 and 94) were scheduled on a biennial rather than annual basis.[63] As a result of the Secretary's analysis under 18(a)(2)(E),[64] the Secretary initially decided to propose more frequent offerings in St. George Basin, North Aleutian Basin, and Norton Basin than would be derived solely from the net social value rankings.[65] On the basis of section 18(a)(2)(F),[66] the Secretary decided to divide the North Atlantic into two separate planning areas, North Atlantic and Mid-Atlantic, and to add one sale (111) in order to provide for biennial leasing in the Mid-Atlantic planning area.[67] Petitioners contend that more adjustments should have been made as a direct result of the Secretary's consideration of section 18(a)(2) factors. However, this court's earlier opinion required the Secretary only to consider whether the factors constituted an absolute or categorical impediment to leasing in a particular area and then to use those factors as part of the balancing process in determining the timing and location of the leasing activity. Petitioners may have struck the balance in a different manner, but they have failed to show that the Secretary's decision was arbitrary or unlawful.

Petitioners' final attack on the adequacy of the Secretary's efforts to base the leasing program on the section 18(a)(2) factors is more troubling. Petitioners point out that while the Secretary utilized the section 18(a)(2) factors as a basis for determining the *frequency* of leasing activity in the various areas, the Secretary himself admitted that "the timing of first sales in an area should not be subject to this analysis."[68] Petitioners contend that this is an admission by the Secretary that he failed to base the timing of the leasing program on his consideration of the section 18(a)(2) factors. At first glance petitioners' argument appears to be correct. The Secretary does admit that he did not base the timing of the first sale in each particular area on his consideration of section 18(a)(2) factors. However, the interpretation of section 18 which must be accepted in order to complete petitioners' argument is not sound.

The Secretary's admission that the timing of the first sales in an area would not be subject to the section 18(a)(2) analysis was based on his realization that "as a factual matter offshore leasing does not begin when this program is approved, but rather it began in 1954 when the first Federal lease sale was held."[69] Thus, "[w]ith the exception of several Alaskan areas, the 'first sale' has already been held in each OCS planning area."[70] The Secretary concluded that as a practical matter some sales

62. JA at 2302.

63. *Id.* at 2303.

64. Section 18(a)(2)(E) requires the Secretary to consider "the interest of potential oil and gas producers in the development of oil and gas resources as indicated by exploration or nomination." 43 U.S.C. § 1344(a)(2)(E) (Supp. V 1981).

65. JA at 2305. Other section 18 considerations led to the ultimate decision to provide for biennial leasing only in the St. George Basin. *Id.*

66. Section 18(a)(2)(F) requires the Secretary to consider the "laws, goals, and policies of affected States which have been specifically identified by the Governors of such States as relevant matters for the Secretary's consideration." 43 U.S.C. § 1344(a)(2)(F) (Supp. V 1981).

67. JA at 2306.

68. *Id.* at 2301.

69. *Id.*

70. *Id.*

on the prior schedule must be continued on the revised schedule because presale steps for these sales have been long under way and it would be grossly ineffective to reschedule these sales for later in the program. Petitioners contend that this is tantamount to basing the timing of the sales *solely* on administrative convenience, something this court rejected in *Watt I*.[71] However, the Secretary's decision to permit these sales to continue was not based solely on administrative convenience, but on the Secretary's interpretation of the *congressional intent to expedite* offshore lease sales, particularly in frontier areas.

Congress expressly stated that "leasing shall be permitted to continue" throughout the period necessary for the formulation and reformulation of the leasing program and "for so long thereafter as such program is under judicial or administrative review."[72] Further, the 1978 amendments envisioned moving into previously undeveloped or frontier areas.[73] The adoption of petitioners' interpretation of section 18 would mean that each time the Secretary revised the five year program, he would have to rearrange the schedule and defer sales in low net-social-value areas. The result would be that areas which, although ranking low in comparison to other areas, nevertheless have potentially recoverable oil and gas benefits substantially exceeding expected costs, might never be leased, whereas proven areas would be subject to incessant leasing. This would also aggravate the inequitable sharing of environmental risks which presently exists because leasing activity is primarily limited to the proven areas of the Gulf of Mexico and Southern California. Thus, the Secretary's decision to permit some sales to proceed on schedule, notwithstanding the fact that a consideration of section 18(a)(2) by itself might dictate otherwise, was not based solely on administrative convenience, but on the Secretary's correct belief that other section 18 interests could *also* be considered in determining the timing of leasing activity.

> The fact that we do not have control over the timing of first sales in most areas does not negate the Department's responsibility to schedule those where we do have control on a rational basis, that is, at a point when the Department is prepared to meet its responsibilities under the OCS Lands Act, NEPA, and other applicable statutes. These were, in fact, the primary factors in determining the scheduling of first sales.[74]

Similarly, the Secretary quantified what to him seemed possible to quantify, and evaluated other factors qualitatively.

We therefore reject petitioners' argument that the program is not based on the Secretary's consideration of the factors listed in section 18(a)(2). The Secretary properly concluded that none of these factors precluded him from arranging the schedule as he did and there is no serious dispute over whether these factors were used to strike the proper balance under section 18(a)(3).[75]

V. The Section 18(a)(3) Cost Benefit Analysis

Under section 18(a)(3) the Secretary is required to "select the timing and location of leasing, to the maximum extent practicable, so as to obtain a proper balance between the potential for environmental damage, the potential for the discovery of oil and gas, and the potential for adverse im-

71. *Watt I*, 668 F.2d at 1314–15 (Secretary cannot base timing of lease sales *solely* on administrative exigencies).

72. 43 U.S.C. § 1344(d)(3) (Supp. V 1981).

73. *Watt I*, 668 F.2d at 1295.

74. JA at 2301.

75. Our conclusion concerning section 18(a)(2) completely defeats petitioners' argument that the Secretary's section 18(a)(3) analysis was flawed due to "[t]he manifest errors in the Secretary's consideration of § 18(a)(2) . . . and his failure to base his timing and location decisions on these factors." California Brief at 150. Since we conclude that the Secretary's section 18(a)(2) analysis was adequate, his section 18(a)(3) analysis cannot be faulted on that basis.

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pact on the coastal zone."[76] In *Watt I* the court noted that "within the section's 'proper balance' there is some notion of 'costs' and 'benefits,' recognizing that 'costs' in this context must be a term of uncertain content to the extent it is meant to stand for environmental and social costs."[77] The court expressed concern about one aspect of the cost benefit analysis performed in the original five-year leasing program, finding that the Secretary had failed to explain adequately his determination of net economic value, particularly the economic effects of delaying leasing.[78] On remand the Secretary more fully explained the basis of his net economic analysis and engaged in a cost benefit analysis. Petitioners in the present case do not argue that the Secretary failed to engage in the cost benefit analysis, nor do they contend that he failed to explain what he was doing. Instead, they attack several of the factual findings and methodological assumptions at the base of the Secretary's cost benefit analysis. We find these arguments unpersuasive.

It is first important to understand what is being evaluated. As noted above petitioners challenge the factual basis and the methodology used by the Secretary in various aspects of the cost benefit analysis. These are aspects of the analysis which fall within what the court in *Watt I* described as the "frontiers of scientific knowledge."[79] The facts used by the Secretary in performing the analysis are largely predictive in nature, and the methodology utilized was necessarily novel because this type of analysis has not been performed extensively in the past. Thus, as the court in *Watt I* observed, great deference is afforded to the Secretary in these areas. "Where existing methodology or research in a new area of regulation is deficient, the agency necessarily enjoys broad discretion to attempt to formulate a solution to the best of its ability on the basis of available information."[80] Therefore, although we are obligated to review the factual findings of the Secretary in order to determine that they are supported by substantial evidence in the record, we realize that these findings must be somewhat speculative. Further, we are required to sustain the methodology and assumptions made by the Secretary if they are reasonable.

It is also important to realize that because the analysis is speculative and predictive in nature, it could go on forever. However, it is clear that Congress did not want the Secretary to spend years developing a five-year leasing program. Indeed, the Secretary was required to submit the first proposed program to Congress, the Attorney General, and the Governors of the affected states within nine months of the effective date of the 1978 amendments.[81] Thus, "the final decision as to how much analysis is necessary in view of the available data must be the agency's subject to judicial review only for obviously incorrect results or methodology."[82] In sum, the aspects of the Secretary's cost benefit analysis challenged are aspects with regard to which the Secretary is entitled to substantial deference. It is important to keep this in mind, as we evaluate the Secretary's performance under section 18(a)(3).

76. 43 U.S.C. § 1344(a)(3) (Supp. V 1981).

77. *Watt I*, 668 F.2d at 1318.

78. *Id.* at 1320-21.

79. *Id.* at 1301, quoting *Industrial Union Department, AFL-CIO v. Hodgson*, 499 F.2d 467 (D.C. Cir.1974).

80. *Id.* n. 18 (citing *Permian Basin Area Rate Cases*, 390 U.S. 747, 811, 88 S.Ct. 1344, 1383, 20 L.Ed.2d 312 (1968)).

81. 43 U.S.C. § 1344(c)(3) (Supp. V 1981). Congress also apparently contemplated the adoption of a final leasing program within 18 months of the amendment's effective date. *Id.*, § 1344(d)(3). This undermines Petitioner Florida's argument that "a minimum of three years for environmental data collection and one year for data synthesis is needed to have the necessary information to perform an adequate cost/benefit analysis as required by ... (Section 18)." Statement of Petitioner Florida at 3.

82. *Watt I*, 668 F.2d at 1317 n. 224, quoting *Massachusetts v. Andrus*, 594 F.2d 872, 886 (1st Cir.1979).

[10] The Secretary's cost benefit analysis revolves around a calculation of each planning area's "net social value." Net social value is calculated by subtracting external costs from net economic value.[83] Net economic value in turn is defined as the difference between the market value of the expected hydrocarbon resources in a planning area less the direct costs of producing those resources and transporting them to market.[84] External costs are the "environmental and socio-economic costs which are not normally included in the costs of operations involved in OCS oil and gas exploration, development, production and transportation."[85] Petitioners do not attack the generalized formula used by the Secretary in calculating the net social value of each planning area. Instead, they attack the adequacy of the calculations. However, none of these challenges persuades us that the Secretary's analysis was defective.

A. *Calculation of Net Economic Value*

Petitioners first challenge the Secretary's calculation of net economic value. They contend that the Secretary's determination of net economic value was completely inaccurate because it failed to reflect the costs and benefits of delaying lease sales. According to petitioners, the Secretary did not consider the possible benefits or costs of delaying lease sales beyond the first year of the program and therefore his analysis was skewed. However, it is the petitioners' argument which is skewed and therefore unconvincing.

The Secretary in his initial calculation determined net economic value as if all oil in all areas would be leased and developed in the first year of the program.[86] This was reasonable because the Secretary was trying to calculate the *relative* ranking of each of the planning areas, in addition to determining whether each of the planning areas should be leased. Petitioner would have the Secretary initially determine the timing of each lease sale in order to determine when the oil would be developed and then calculate the costs and benefits of leasing at that time in order to determine whether and when each planning area should be leased. Petitioners in effect claim that the measure used to determine the timing and location of lease sales must itself factor into that conclusion the timing of the lease sales. This is an illogical proposition. The Secretary's actions were more reasonable. After calculating the costs and benefits of leasing in each area under the assumption noted above, the Secretary computed the cost of delay for each planning area.[87] Therefore, the Secretary evaluated each area on a relative basis initially and then considered the cost of delay for each planning area. This was entirely permissible.

Petitioners next contend that the Secretary's calculation of net economic value was defective because it was based on two arbitrary assumptions. They first assert that the Secretary unreasonably assumed that the price of oil would increase in real terms at a rate of one percent per year. Second, they complain because the Secretary assumed that the production costs in all planning areas would in real terms remain constant throughout the five year period. We reject both of these arguments.

The Secretary's assumption that the price of oil would increase by one percent per year in real terms is not unreasonable and is supported in the record. The Secretary noted that the one percent rate was consistent with the assumptions the Department of Interior had made in most lease sale designs in the past year, that it was within the low range estimated by a study completed in 1980 comparing seventeen major studies of petroleum price forecasts, and that since the study's completion, world price trends had moderated somewhat, justifying reliance on a somewhat lower long-

83. JA at 1283.

84. *Id.* at 1251.

85. *Id.* at 1271.

86. *Id.* at 1332.

87. *Id.* at 1316.

run trend.[88] Petitioners contend that the study relied upon by the Secretary predicted that the most likely rate of increase would be three percent. This may be true, but the Secretary was free to use his expertise to accept the one percent growth rate which the study stated was within the realm of possibility, particularly in light of recent trends which indicate that many of the earlier studies overstated the rise in the price of oil.

We also find that the Secretary's assumption that production costs in all planning areas would remain constant in real terms throughout the five year period was reasonable. Petitioners contend that the only reasonable assumption was that production costs in frontier areas would decline as technology improved. The Secretary acknowledged that production costs *might* decline in frontier areas. He therefore noted that if that should happen resources of average value in frontier areas would yield greater benefit if produced later. He correctly noted that a two percent decline in costs in such areas would narrow the differences in net economic value between programs with earlier and more frequent leasing in such areas and programs which were less aggressive. However, he concluded that such differences were not sufficient to require adjusting the schedule because it was likely that resources of above average value would be discovered and produced first in such areas, at a time when the cost of production was still high. He further stated that the market was capable of anticipating technological developments better than the government and that, accordingly, the market would delay investments whenever greater profits could be achieved. The Secretary's assumption was therefore reasonable, and we conclude that he adequately considered changes in production costs in frontier areas.[89]

B. *Calculation of External Costs*

Petitioners also challenge the Secretary's calculation of external costs, raising three particular challenges to this aspect of the Secretary's cost benefit analysis. They first contend that the Secretary understated the cost of potential oil spills because no effort was made to determine whether the oil spills studied by the Secretary would have a similar effect in each of the planning areas. Second, they contend that the Secretary failed to count the cost of oil spills of less than a thousand barrels and that this resulted in a serious understatement of the costs. Third, they contend that the Secretary arbitrarily assumed that cleanup costs for oil spills would be the same in all regions. We find each of these arguments unpersuasive.

In determining the cost of major oil spills (oil spills greater than a thousand barrels) the Secretary relied on the most reliable information available, a study evaluating damage estimates for the only five oil spills which had been subjected to economic analysis.[90] The Secretary threw out the high and low values, converted the remaining values to 1981 dollars, and arrived at a range of $100 to $1900 per barrel for the cost of the cleanup for major oil spills.[91] The Secretary then assumed that this range would be the lower and upper limits of environmental damage caused by oil spills in any one of the planning areas. Finally, the Secretary evaluated each planning area to determine where, within that range, the area would fall.[92]

Petitioners contend that the Secretary did not adequately consider the differences between the environments in the planning areas under review and those in which the oil spills in the study occurred and that as a result the range used by the Secretary was too restrictive. They claim that the Secretary should have engaged in additional analysis to determine whether the environments of the coasts where the oil spills occurred were similar to those of each planning area. However, we find the Secretary's method reasonable. It was reasonable to base the range of estimates on actual events which had been quantified in the past. This range was based on a study of the only five major oil spills which the Secretary felt provided reliable evidence. Petitioners can cite no major oil spills which the Department did not consider. The Secretary's methodology was far from irrational, and we have been provided no more reasonable alternative.

Petitioners' complaint about the Secretary's failure to quantify the costs of oil spills of less than a thousand barrels is also misdirected. Petitioners intimate that the Secretary completely failed to consider the costs of oil spills of less than a thousand barrels and that this understated the external costs. However, petitioners ignore the methodology chosen by the Secretary. The Secretary did not base his entire section 18(a)(3) analysis on the cost benefit analysis. Instead, he considered the quantifiable costs in the cost benefit analysis and then later considered costs which he determined could not be quantified.[93] The Secretary specifically noted:

> there were several suggestions that the cost of spills under 1000 barrels should be calculated since they may inflict damage equal to or higher than that of spills over 1000 barrels. These and similar recommendations raise issues which are subject to much debate and disagreement.... [A] number of external costs were not estimated due to the difficulty of establishing values on which there is little consensus. The Department believes these costs exist, but are more appropriately considered in other terms than dollars.[94]

We do not think it was arbitrary for the Secretary to consider the cost of these oil spills in terms other than dollar and cents, particularly when the record before him contained very little reliable evidence on which the calculation could be based.[95]

We also reject petitioners' contention that the Secretary acted arbitrarily in assuming that the cleanup costs for each region would be the same. The Secretary did not identify regional cost differences in oil cleanups. However, his refusal to do so was reasonable. The Secretary noted that, for purposes of the cost benefit analysis, he chose to assume that cleanup costs would not vary from region to region because "it is difficult to identify what the regional cost differences might be, and [further] location, type, and size of spill [will] be the primary factors" in determining the costs of oil cleanup.[96] Petitioners claim that this assumption was arbitrary because it can be proven that the cost of cleanup in the Arctic environment would be much higher than in other areas. They cite one study to support this contention, a study showing that cleanup costs for three oil spills off

88. *Id.* at 1334–35.

89. We also reject petitioners' contention that the Secretary's net economic value determination was defective because (1) it ignored production cost differences among planning areas, (2) it was based on an assumption that recoverable gas resources would be produced in Alaska and delivered to market, and (3) it was based on a tax rate which was not supported by the record.

The tax rate chosen by the Secretary had no effect on the net economic value determination, because the Secretary added back into the analysis the exact amount of taxes deducted earlier—48%. The amount of the assumed tax rate therefore had no impact on the analysis. The Secretary's assumption on the economic feasibility of producing gas in Alaska could reasonably be drawn from evidence in the record. JA at 1242–43, 1254. Moreover, the Secretary considered the effect of an error in this assumption. *Id.* at 1254–55. Similarly, his assumption on the production costs in different areas was reasonably based on Department of Interior experience in many areas, supplemented by a Department of Energy Report which was especially helpful in determining the costs in frontier areas. *Id.* at 1328.

90. JA at 1461.

91. *Id.* at 1487.

92. *Id.* at 1486.

93. *Id.* at 1271.

94. *Id.* at 2314.

95. The evidence available to the Secretary indicated that the average oil spill under 1000 barrels was only 1.2 barrels. JA at 2495. This shows that the potential impact of such oil spills would be minimal and further justifies the Secretary's decision to consider those impacts in terms other than dollars.

96. JA at 1469.

Alaska's coast ranged from $321 to $32,347 per barrel, figures far higher than the range used by the Secretary.[97] However, the higher figure, which is the only figure outside the range of oil cleanup costs considered by the Secretary, could have rationally been rejected by the Secretary since it was based on a very small oil spill[98] which was not shown to be typical. Further, the wide range of the costs in the cited study only underscored the Secretary's conclusions that it would be extremely difficult to identify what the regional cost differences might be and that other factors, which had been considered, would more accurately reflect the actual costs.

C. *Methodology for Calculating Costs and Benefits*

Petitioners final attack on the Secretary's cost benefit analysis is directed toward the methodology used by the Secretary. They contend that the entire analysis is flawed because the Secretary did not measure costs and benefits on the same basis. Petitioners argue that in calculating the net economic value of each area the Secretary did not discount to present value the estimated benefits from oil production. On the other hand, petitioners assert, the Secretary did discount to present value the external costs associated with that development. The result, petitioners conclude, is either an overstatement of benefits or an understatement of costs which is so great that the entire five year program is flawed. However, petitioners overstate the magnitude of the Secretary's error and, more importantly, ignore the Secretary's overall procedure which rendered that error insignificant.

The Secretary's calculation of net economic value was based on a formula involving three factors: (1) the estimated residual value per barrel of oil (the value of the oil after taxes and royalties are paid); (2) the taxes received by the government as a result of development; and (3) the royalties received by the government.[99] What petitioners fail to acknowledge is that the Secretary did discount to present value the estimated residual value per barrel of oil. The Secretary expressly stated that the residual value represented the "net *present* value which is the residual left after royalties and taxes have been paid."[100] Thus, one of the three factors was discounted to present value before it was included in the calculation. Since taxes were calculated into the formula in terms of percentage rather than dollars,[101] and since percentages (unlike dollars) do not change in value over time, there is no need to discount the second factor to present value. Therefore, the only factor which was not discounted to present value was the amount the government would receive in royalty payments.

Petitioners contend that even if the Secretary failed to discount only the royalty factor, the resulting miscalculation is still so large that the entire program is unsupportable. We reject that argument because it ignores the overall process the Secretary utilized in promulgating the five year program. Petitioners' argument implies that the Secretary felt that his cost benefit analysis was so exact that he could rely on it exclusively in determining when and where leasing activity would occur. This is simply not the case. The Secretary's cost benefit analysis was far from precise and he knew it. Accordingly, he made adjustments to allow for errors in his calculation and was cautious as to the extent he relied on his analysis. When the Secretary's failure to discount royalties to present value is viewed in light of the overall scheme, its significance lessens dramatically.

The Secretary's cost benefit calculations were not as precise as they could have been, since they were slanted in favor of lower benefits and higher costs. This is not to say that they were erroneous. The Secretary merely realized the uncertainty inherent in such predictions and he made allowances to give him room for error. For example, the Secretary deliberately overstated costs to an extent, noting that "when judgments were needed on the dollar value to use for damages on how an area's environmental resources should be rated, the practice was *always* made to err on the high side."[102] The Secretary also observed that he could have justifiably used lower cost figures. "[E]stimates of expected external costs are likely overstated [because] development of the United States' OCS oil and gas resources is conducted in an exceedingly safe and environmentally sound manner."[103] Similarly, benefits were consciously understated. For example, the Secretary noted:

> The estimates of net economic value did not include any estimate of the benefits from reduced requirements for the Strategic Petroleum Reserve due to higher production levels. The net economic benefits are thus understated by 5% to 10%.

In addition, the estimates of net economic value did not include any allowance for "premium" value of domestic oil production above the value set by the world price. Such a premium may result from decreased vulnerability to import disruptions. Such estimates range from a few dollars to nearly $100 per barrel, but there is substantial uncertainty as to their validity. By neglecting these benefits of decreased economic disruption that accrue from import disruptions when domestic price is higher, the net economic value estimates again understate the potential national benefits of OCS oil and gas production.[104]

We are not suggesting that the Secretary's error with respect to the calculation of royalties was exactly offset by these other assumptions. We merely intend to show that the Secretary allowed room for such errors. More importantly, the Secretary realized that the cost benefit analysis should be used only for generalized conclusions.[105] He did not think that the analysis would provide an adequate basis for making narrow distinctions between planning areas. Petitioners do not suggest that the error with respect to royalties would have resulted in the deletion of any area from the program. They assert only that had royalties been discounted to present value, the rankings of six of the nine planning areas would change.[106] The Secretary was aware that his analysis might be flawed in some respect so he took steps to allow room for just such errors and was careful to limit the manner in which he used the resulting calculations. Thus, while the Secretary's calculations may have been more precise had he discounted the royalties to present value, we do not think this minor error flawed the

97. California Brief at 89.

98. The per barrel cost of cleaning up extremely small spills does not accurately reflect the average cleanup cost because "as the number of barrels spilled increases, the dollar cost of cleanup per barrel decreases. In the case of a small [spill], all the cost of mobilization of [equipment] is incurred, even though not many barrels of oil need to be collected or contained." JA at 1468.

99. The following formula was used by the Secretary to determine net economic value:

$$\text{Net economic value} = \text{Residual Value} + \frac{5.8}{.52}$$

The equation considered the effects of taxes at a 48% rate (1 - .48 = .52) and royalties of ⅛ (⅛ of $35 (the estimated market price of oil in the first year of the program) = 5.8). JA at 1328.

100. JA at 1327. (emphasis added). The Secretary noted that most economic models calculated residual value in this manner and that "[f]or purposes of this analysis the net economic value per barrel of resource was calculated by finding *this* residual value per barrel in each area and extrapolating to the net economic value." *Id.* at 1327 28. (emphasis added).

101. *See supra* note 98.

102. JA 1278. (emphasis added).

103. *Id.*

104. *Id.* at 1332.

105. For example, the Secretary noted that the cost portion of his analysis should be used only for very general conclusions.

> Given the uncertainty of the data on which the analysis was based, and the necessity of heavy reliance on judgment and opinion, the external cost estimates should be considered, at best, as an order of magnitude approximation. As such, prudent use of these estimates would only make distinction between differences from area to area if they are approximately an order of magnitude in size (that is, one estimate is more than or less than 10 times the other).

Id. at 1277.

106. Petitioners' Supplemental Memorandum concerning the Royalty Issue at 2.

entire five year program so as to require a remand.

In summary, petitioners challenge the Secretary's cost benefit analysis on a variety of fronts. However, they fail to recognize the limited scope of our review. Too often they attempt to prove that the Secretary's decision is not supported by evidence in the record by citing evidence which conflicts with the Secretary's conclusion. They ignore the evidence which supports the Secretary's decision or claim that it is not as persuasive as the evidence to which they cite. However, as this court recently noted

> Disagreement among the experts is inevitable when the issues involved are at the "very frontiers of scientific knowledge," and such disagreement does not preclude us from finding that the Administrator's decisions are adequately supported by the evidence in the record.... It is not our function to resolve disagreements among the experts or to judge the merits of competing expert views.... Our task is the very limited one of ascertaining that the choices made by the Administrator were reasonable and supported by the record.... That the evidence in the record may also support other conclusions, even those that are inconsistent with the Administrator's, does not prevent us from concluding that his decisions were rational and supported by the record.[107]

On the basis of all the evidence before him the Secretary's cost benefit analysis was reasonable. Even if we disagreed with some of the conclusions he reached, we would be unable to remand the program on that basis.

VI. Receipt of Fair Market Value—Section 18(a)(4)

In addition to the principles stated in subsections 1, 2 and 3 of section 18(a), the Act requires that the five-year leasing program accord with the principle that "[l]easing activities shall be conducted to assure receipt of fair market value for the lands leased and the rights conveyed by the federal government."[108] The term fair market value is not defined in the statute, so the Secretary adopted the following definition for purposes of his analysis.

> "Fair market value" is defined as the amount in cash, or on terms reasonably equivalent to cash, for which in all probability the property would be sold by a knowledgeable owner willing but not obligated to sell to a knowledgeable purchaser who desired but is not obligated to buy.[109]

Petitioners do not attack this definition, but they do contend that the program adopted by the Secretary does not assure receipt of fair market value. We must reject their contention once again.

[11] Petitioners assert that the large size of the lease offerings and the accelerated rate of leasing combine to drive the prices of the leases down.[110] However, even assuming that lower bids will result, petitioners have not established that the Secretary violated the Act.

Section 18(a)(4)'s requirement that the program assure receipt of fair market value does not mandate the maximization of revenues, it only requires receipt of a fair return. The Secretary acknowledged that the accelerated rate of leasing might ordinarily result in less intense competition and lower bids for some tracts. He pointed out, however, that the contrived intensity of competition achieved by the government's prior use of its monopoly power may have produced prices in excess of fair market value and thus not socially optimal.

> [The] monopolistic tendencies of past leasing rates raise the possibility that lease prices were at least somewhat higher as a result. The question now is, what is the effect from the perspective of fair market value of increasing the rate of leasing in order to catch up on the amount of investment in exploration? Lease prices could be held at higher levels by continuing to restrict the availability of leases. Such a policy could result in prices that would be higher than those in a market in which supply is competitively determined. It would, however, be tantamount to exertion of monopoly power by the government. Losses to the economy would result just as they do from private monopolies. It would be very costly to the Nation to exercise the government's monopoly over the supply of OCS leases as the means for assuring receipt of fair market value. Other means are available that are far less costly to the nation's economy.[111]

Thus, rather than attempt to maximize the amount of money the government could receive by delaying the sale of leases, the Secretary decided to rely on the competitive bidding process to assure receipt of fair market value, concluding that that process did "much to assure that the bids the government receives represent the value of the leases under the supply and demand conditions at the time of the lease sale."[112] This conclusion was a reasonable one.

The process for receiving bids on leases is not an open public auction but a competitive sealed bid procedure under which none of the bidders knows what its competitors will bid. The Secretary observed that there was evidence that one and two bid lease sales have not yielded surplus profits to their owner, and that such leases have not been made at less than fair market value.[113] As added insurance that fair market value would be received on tracts with modest prospects, the Secretary increased the minimum bid per acre from $25 to $150.[114] Thus, the Secretary's heavy reliance on the competitive bidding process to assure receipt of fair market value was not unreasonable.

Moreover, the Secretary did not rely exclusively on the competitive bidding process to assure that fair market value would be received. As a double check, the Secretary adopted evaluation procedures designed to assure further the government's receipt of fair market value. Petitioners contend that these procedures are not sufficient, noting that they are less comprehensive than the tract evaluation previously used. However, we cannot conclude that these procedures are unreasonable or that they will not assure the receipt of fair market value, particularly when they are viewed merely as a complement to the effect of the competitive bidding process.

Under the prior evaluation procedure, each tract put up for lease was evaluated by the government to determine what minimum price should be bid in order to assure receipt of fair market value. The Secretary noted that this was not the most effective way of assuring the receipt of fair market value because evaluations were often made on tracts for which no bids were received. In an effort to avoid the costly and unnecessary task of estimating the value of tracts which would not be leased, the Secretary, observing that the tract evaluation system was best viewed as a mechanism to deter any tendency for bidders to exploit unusual situations or new conditions by systematically underbidding, attempted to design a cost effective sample of tracts for evaluation. Although the program is apparently still in the testing phase,[115] the general out-

107. *Lead Industries Association v. EPA*, 647 F.2d 1130, 1160 (D.C.Cir.), *cert. denied*, 449 U.S. 1042, 101 S.Ct. 621, 66 L.Ed.2d 503 (1980).

108. 43 U.S.C. § 1344(a)(4) (Supp. V 1981).

109. JA at 1355.

110. Petitioners particularly emphasize the accelerated rate of leasing, contending that "[i]f more and more tracts are offered, bids will be submitted based on less and less information. Uncertainty will increase. As uncertainty over the value of the resource increases, expected profits from the lease decrease and, as expected profits decrease, the willingness to pay of the prospective bidder decreases." California Brief at 154 n. 1.

111. JA at 1361.

112. *Id.*

113. *Id.* at 1359.

114. *Id.* at 2298.

115. The Secretary asserts that the "new" tract evaluation procedure is merely a proposal, which will not be implemented until tested. "Until a system is validated it will not be implemented, and the prior procedures will continue to be utilized." Respondents' Brief at 97. Petitioners dispute this representation, but do not suggest that the procedures have been implemented. Petitioners' Reply Brief at 72. We do not need to resolve the dispute, because we

lines laid down by the Secretary are adequate to assure that the evaluation system will perform its function to assure that the government receives fair market value for its leases.

Under the proposed program the tract evaluation will be made *after* bids are received. Each high bid will be subjected to a quantitative evaluation developed to decide whether to accept or reject bids and, when validated, to a comparative evaluation. Bids passing this initial screening will then be evaluated on the following basis. Bids received on leases containing proven, drainage, or development tracts will *all* be evaluated. Bids received for frontier areas will be evaluated in two ways. First, an appropriate sample of the tracts receiving bids, depending on the particular sale, but generally in the range of thirty percent, will be evaluated. Second, a *random* sample of five percent of the tracts will be evaluated.[116] This system will adequately allow the Secretary to deter bidders from subverting the market system and will do so in a cost-effective manner. There may be more effective means available, as petitioners assert, but that does not mean that the chosen method is unreasonable. Therefore, the proposed evaluation process, coupled with the Secretary's reasonable reliance on the integrity of the competitive bid process, is sufficient to assure that the fair market value is received.[117] The statute requires nothing more.

VII. Effects of the Five Year Leasing Program on Washington and Oregon

Petitioners Washington and Oregon contend that the Secretary failed adequately to consider the effects of the five-year leasing program on their states. In particular they contend that the Secretary's analysis with respect to the impact of the program on Washington and Oregon was so inadequate that it violated section 18(a)(1) and section 18(a)(2) of the OSCLA and section 102 of the National Environmental Policy Act. We reject all of these arguments.

A. *Compliance With Section 18(a)*

Washington and Oregon challenge the adequacy of the Secretary's section 18(a) analysis in two respects. First, they contend that section 18(a)(1) and section 18(a)(2) require the Secretary to evaluate each region of the outer continental shelf even if no leasing activity is contemplated there and that the Secretary failed to do this. However, this argument is flawed because it is based on an erroneous interpretation of section 18.

[12] Section 18 does not require the Secretary to engage in the fruitless exercise suggested by Washington and Oregon. The purpose of the Secretary's section 18 analysis is to determine which areas will be leased under the five-year leasing program and when those areas will be leased. If the Secretary has already determined that no leasing activity will occur in a particular area there is no need to fully evaluate that area. Thus, if the Secretary adequately considered the costs to Washington and Oregon associated with the leasing in other areas he has not violated the statute.

Washington and Oregon next assert that the Secretary's analysis is inadequate because he did not adequately consider the effect of oil spills from Alaska and Northern California which could impact on Washington and Oregon. We disagree. There is no dispute that the Secretary expressly took into account the impact on Washington and Oregon in his consideration of section 18(a)(2)(B)—arriving at a quantified estimate of 300 million dollars.[118] Washington and Oregon complain because these costs were largely attributable to the costs of potential oil spills from oil tankers from Alaska. They argue that the Secretary ignored other potential costs, including the cost associated with spills from other sources and the cost of damage to fish and wildlife. However, these concerns are not well-founded.

[13] It is undisputed that the Secretary considered the costs of oil spills from Alaska and California and concluded that most of the damage would be inflicted on those two states. Oregon and Washington contend that more of the impacts will occur in Oregon and Washington because of the northward flow of the Davidson current during the winter months. However, even if the Secretary erred in deciding *where* these costs would occur, his analysis is still sustainable as long as he adequately considered *how much* the costs would be. Washington and Oregon dispute this conclusion, asserting that the accuracy of the Secretary's determination of *where* the impacts will occur is important because their shores are different in terms of environmental sensitivity from those of California. However, the Secretary reasonably concluded that "the ecological damages for Washington and Oregon would be expected to be similar to those of Central and Northern California."[119] This is a rational assumption, especially in light of the fact that neither Washington nor Oregon presented the Secretary with any information to the contrary, despite their opportunity to do so. Thus, we conclude that the Secretary's evaluation of the impacts on Washington and Oregon comported with the requirements of section 18(a).

B. *Compliance with NEPA*

[14] Section 102 of the National Environmental Policy Act (NEPA) requires all agencies of the federal government to include in their recommendations for major federal actions significantly affecting the quality of the human environment, a detailed statement of "the environmental impact of the proposed action [and] any adverse environmental effects which cannot be avoided should the proposal be implemented."[120] Washington and Oregon challenge the environmental impact statement prepared for the five year program, contending that it inadequately considered the program's environmental impact on Washington and Oregon.[121] The focus of Washington and Oregon's concern is the Secretary's failure to consider the effect of potential oil spills on the Washington and Oregon environment.[122] However, we find the Secretary's evaluation of the environmental impact of such oil spills adequate.

The supplemental environmental impact statement which was filed as a part of the five year program expressly discusses the effect of oil spills on the Pacific region of which Washington and Oregon are a part. It explains in detail the effects of a spill on fish in this region, including the stocks of concern to Washington and Oregon: salmon, herring, steelhead trout, shrimp, and crabs.[123] It also evaluated the effect of an oil spill on tourism and recreation in the region, concluding that "loss to both beach and water recreation would be very high for the area where any large oil spill contacted."[124] And, the Secretary also considered the possibility that support bases would be built in Washington and Oregon,[125] even though he concluded that "the number and location of new facilities are dictated by a number of marketing factors making it extremely difficult to accurately predict or assess the impacts of new facilities."[126]

Washington and Oregon may have hoped that the Secretary would perform a more extensive evaluation of the effect of the

116. JA at 2298.

117. *Id.* at 2294.

118. *Id.* at 1282.

find both the "old" and the "new" tract evaluation procedures sufficient when considered in conjunction with the reasonable reliance on the market and the increased minimum bid price, to assure receipt of fair market value.

119. *Id.* at 1488.

120. 42 U.S.C. § 4332(B)(i) & (ii) (1976).

121. Brief for Petitioners Washington and Oregon at 25 [hereinafter Washington Brief].

122. Washington Brief at 30–31.

123. Final Supplemental Environmental Impact Statement (FSEIS) at 480–87, 533–37.

124. *Id.* at 501.

125. *Id.* at 469.

126. *Id.* at 886.

five year program on their states. However, they were provided with an opportunity to review and comment upon the draft supplement to the environment impact statement and failed to raise many of the issues they seek to raise now. Those which they raised were adequately addressed, even though the Secretary's conclusions did not conform with those of Washington and Oregon. The environmental impact statement was therefore adequate.

VIII. Compliance With Section 18(f)(5)

Washington and Oregon advance one final attack on the five-year leasing program. They contend that the program violates section 18(f)(5) because the Secretary did not expressly declare when he would make the consistency determination which Washington and Oregon contend is required by section 307 of the Coastal Zone Management Act.[127] As do all of the arguments advanced by petitioners in this case, this argument falls short.

[15] Section 18(f)(5) requires the Secretary "by regulation, [to] establish procedures for ... *consideration* of the coastal zone management program being developed or administered by an affected coastal state pursuant to section [*305 or 306* of the Coastal Zone Management Act of 1972.]"[128] There is no indication that the Secretary must outline when a section 307 *consistency determination* must be made. Indeed, there is some question as to whether a consistency determination is ever required under the leasing program.[129] The section merely requires the Secretary to establish *procedures* for the *consideration* of the coastal zone management program developed by the states pursuant to section 305 or 306. In conformity with this requirement the Secretary issued a regulation requiring that "information concerning the relationship between a state's coastal zone management program and OCS oil and gas activity shall be requested from the Governors of the effected coastal states and from the Secretary of Commerce prior to the development of the proposed leasing program at the time information is requested under [section 18(a)(2)(G)]"[130] This clearly meets the requirement of section 18(f)(5).

Washington and Oregon contend that the legislative history of section 18(f)(5) indicates that the Secretary is required to explain when the consistency determination will be made. However, we read the legislative history to the contrary. Washington and Oregon's argument would have been stronger if Senate bill 9, the 1977 Senate bill, would have been passed. That version of section 18(f)(5) required

> The Secretary [to], by regulation, establish procedures for . . (5) coordination of the program with the management program being developed by any State for approval pursuant to section 305 of the Coastal Zone Management Act of 1972 and *consistency*, to the extent practicable, with the management program of any state which has been approved pursuant to Section 306 of such Act.[131]

However, the House version differed from the Senate version, and the conference committee adopted the House version, stating:

> Both versions provide for regulations as to coastal zone management applicability. The House amendment provides for regulations involving "*consideration*" of a program "being developed or administered" pursuant to section 305 or 306, respectively, of the Coastal Zone Act. The Senate Bill provides for "coordination" of the program with the management program being developed *and also for "consistency" to the extent practicable with the management program.* The conference report is the same as the House amendment. The Secretary is to establish procedures by regulation for consideration of state coastal zone management programs.[132]

Thus, the version of section 18(f)(5) which was ultimately adopted required the Secretary merely to establish procedures for *considering* the programs being developed or administered by the states pursuant to section *305 or 306* of the Coastal Zone Management Act. It did not require him to outline when a consistency determination under section 307 would be made.

IX. Conclusion

The Secretary's second attempt to promulgate a five-year leasing program successfully complied with the requirements of the Outer Continental Lands Act as interpreted by this court in *Watt I*. Petitioners' all-out attack on this program is not well founded.[133] Petitioners' disagreement with the conclusions reached by the Secretary are not a sufficient basis for us to invalidate the program. The Secretary's decision was reasonable and supported by the evidence in the record to the extent required by section 18. Accordingly, the petitions are dismissed and the Secretary's five year program is upheld.

KEY NUMBER SYSTEM

127. 16 U.S.C. § 1456(c)(1) (1976).

128. 43 U.S.C. § 1344(f)(5) (Supp. V 1981) (emphasis added).

129. In *California v. Watt*, 683 F.2d 1253 (9th Cir.1982) cert. *granted*, — U.S. ——, 103 S.Ct. 2083, 77 L.Ed.2d 295 (1983), the Ninth Circuit held that the Secretary is required to issue a consistency determination under section 307 of the CZMA before actually selling oil and gas leases under section 19 of the OCSLA. The Secretary sought review of that decision, contending that section 307 does not apply to such *sales* because the *sales* do not directly affect the coastal zone.

130. 43 C.F.R. § 3310.4 (1982).

131. S.Rep. No. 95-284, 95th Cong., 1st Sess. 16 (1977) (emphasis added).

132. S.Rep. No. 95-1091, 95th Cong., 2d Sess. 105 (1978) (emphasis added).

133. Petitioner Florida's argument that some leasing off its shores should be halted because it has "not been assured that its recommendations [concerning two lease stipulations] have been or will be adopted," Brief for Petitioner Florida at 8, is premature. Nothing in section 18 requires the Secretary to decide what stipulations will be included in individual leases be-

APPENDIX B

SUMMARY OF COMMENTS

ON THE DRAFT PROPOSED PROGRAM

(MARCH 1985)

INCLUDING SUMMARY OF COMMENTS ON

REVISION TO APPENDIX P (AUGUST 19, 1985)

SUMMARY OF COMMENTS ON THE DRAFT PROPOSED 5-YEAR PROGRAM AND IN RESPONSE TO THE MARCH 1985 REQUEST

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SUMMARY OF COMMENTS

I. Introduction

Section 18(a) of the Outer Continental Shelf (OCS) Lands Act Amendments requires the Secretary of the Interior (Secretary) to invite and consider suggestions on preparation of a 5-year leasing program from interested Federal Agencies, including the Attorney General, in consultation with the Federal Trade Commission, and from the Governor's of coastal States affected under the proposed leasing program. The Secretary may also invite or consider any suggestions from the executive of any affected local government in an affected coastal State, which have been previously submitted to the Governor of such State, and from any other person.

Before preparation of the Draft Proposed 5-Year OCS Oil and Gas Leasing Program, an initial request for comments was made on July 11, 1984, with the publication of a Federal Register notice requesting comments (49 FR 28332) and with the mailing of letters to the Governors of all coastal States and various Federal Agencies. Appendix B of the Draft Proposed Program is a summary of the comments received in response to those requests.

On March 22, 1985, the Secretary transmitted copies of the Draft Proposed 5-Year OCS Oil and Gas Leasing Program to the Governors of the affected coastal States and to the heads of affected Federal Agencies for review and comment. A Federal Register Notice requesting public comments on the schedule and policies selected as the Draft Proposed Program was also published on March 22, 1985 (50 FR 11585). Although public views were requested on any topic related to the new 5-year program, respondents were requested to provide comments on the following specific topics:

- The proposed configuration of planning area boundaries.
- The appropriateness of the number of proposed sales and the interval between proposed sales.
- The appropriateness of the location of proposed sales.
- The proposed presale process.
- The proposed means of pursuing flexibility in the new program in light of uncertainty over future oil and gas prices and national energy needs.
- Whether considerations such as the following concerning the level of the minimum bid would warrant varying the current minimum bid level of $150 per acre on a nationwide or planning area basis: (1) changes in economic conditions such as oil prices; or (2) potential effects on the number of tracts leased or the rate of exploration and development.
- Whether the tract size limit of 5,760 acres ought to be expanded; and whether enlargement of the maximum tract size is an alternative which would achieve effects comparable to varying the minimum bid. Under

section 18(b)(1) of the OCS Lands Act, the Secretary of the Interior has the authority to enlarge the maximum tract size if necessary to comprise a reasonable economic production unit.
- Whether there are subareas within planning areas which should be subject to special considerations, either in the presale planning process for each sale or, more generally, within the 5-year program itself, and what those considerations should be.

In addition to the request for comments on the major proposals contained in the Draft Proposed Program, industry respondents in particular were requested to rank all 26 planning areas in the Draft Proposed Program. Only 24 planning areas were under consideration in July 1984 when the initial Federal Register Notice requesting comments was published. Under the Draft Proposed Program, the OCS was reconfigured into 26 planning areas by dividing the South Atlantic into two areas (South Atlantic and Straits of Florida) and by subdividing the planning areas offshore of California from two to three.

Industry was requested to provide separate rankings for hydrocarbon potential and for exploration and development interest for the 26 planning areas. It was requested that both sets of rankings be based on estimates of resources expected to be unleased as of mid-1986. See Appendix D for an analysis of the industry rankings.

This analysis of comments is organized into four major sections following the Introduction. Section II is an analysis of the responses by number and geographic distribution. Section III is an analysis of comments by respondent's category, such as Federal Agencies, Governors, industry, etc. Section IV is a summary of comments by subject.

II. Analysis of Responses

A. Number of Responses

As of July 15, 1985, a total of 337 responses on the Draft Proposed Program were received in response to the Federal Register notice of request. The closing date for receiving comments was May 20, 1985.

To facilitate the analysis and summary, letters of comment were divided into eight categories based on type of organization, agency, or special interest. The remainder of this section is a numerical summary of comments received within each category. The number of responses by category is:

Federal Agencies	12
Governors	30
State Agencies	14
Local Governments/Agencies	29
Oil and Gas Industry/Associations	19
Environmental/Other Interest Groups	21
General Public	208
Congress	4
Total	337

1. Federal Agencies

Responses came from nine Federal Agencies having involvement with OCS matters or the leasing program. Comments were received from the U.S. Departments of Defense, Energy, Justice, State, and the Navy; National Aeronautics and Space Administration (NASA); the U.S. Coast Guard (USCG); National Oceanic and Atmospheric Administration (NOAA); and the U.S. Environmental Protection Agency (EPA). Two letters were submitted by NASA. The second letter contained a statement of their position intended to replace and clarify the statement in the first letter. Two letters were submitted by the U.S. Coast Guard, one from headquarters and a second from the 12th Coast Guard District in Alameda, California.

2. Governors

Letters were received from the Governors or their representatives of 23 coastal States. Letters signed by Governors were submitted by 20 States including Alabama, Alaska, California, Connecticut, Delaware, Florida, Georgia, Louisiana, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, North Carolina, Oregon, Rhode Island, South Carolina, Texas, Virginia, and Washington. Views representing three States - Hawaii, Mississippi, and New York - were submitted in letters signed by officials representing the Governors. Letters submitted by California, Florida, and Oregon included attachments referencing comments received by the respective States from agencies, local governments, other interested parties, and citizens.

Five States were represented by more than one comment letter: Florida (2), Maryland (2), Massachusetts (2), Texas (2), and Virginia (3).

3. State Agencies

A total of 14 letters were received from State agencies, legislatures and commissions, exclusive of those representating the Governor. Comments representing State Agencies were received from 8 States: California, Florida, Georgia, Maine, North Carolina, South Carolina, New York, and Pennsylvania. Eleven letters were submitted by State legislators including 5 from California and one each from Florida, Georgia, Maine, New York, Pennsylvania, and South Carolina. Letters were also received from the California Department of Justice, California Coastal Commission, and the North Carolina Department of Natural Resources and Community Development.

4. Local Governments

Responses from local governments received directly by the Department of the Interior totaled 29. All comments in this category came from California. Cities and counties accounted for 24 of the responses. The remainder came from associations of governments (3), an air pollution control district (1), and a county resource management agency (1).

5. Environmental and Other Interest Groups

State, regional, and local environmental and other interest groups provided 18 of the 21 letters from Environmental and Other Interest Groups commenting on the Draft Proposed Program. The three national organizations

that submitted comments included Natural Resources Defense Council (NRDC) Greenpeace, and American Fisheries Society. NRDC's comments were submitted on behalf of themselves, Sierra Club, Environmental Policy Institute, Conservation Law Foundation of New England, and Friends of the Earth.

Most of the comments from State, regional, and local organizations came from California. Comments from groups outside of California included Lone Star Chapter (Galveston, Tx.) of the Sierra Club; Massachusetts Audubon Society; Volusia/Flagler (Ormond Beach, FL) Sierra Club; Earth First, People for the Ethical Treatment of Animals, and Friends of Whales (Gainesville, FL); and Florida Public Interest Research Group, Inc. (Tampa, FL).

6. Oil and Gas Industry

There were 18 letters from respondents representing the views of both the oil and gas industry and principal industry associations. Apart from oil and gas exploration and production companies, letters were received from five industry associations or business groups, including National Ocean Industries Association, Alaska Oil and Gas Association, Western Oil and Gas Association, Chamber of Commerce of the United States, and American Petroleum Institute.

The March 22, 1985 Federal Register Notice specifically requested industry to submit rankings of all 26 planning areas. Separate rankings for hydrocarbon potential and for exploration and development interest were requested. Nine companies submitted rankings; 6 companies submitted rankings of all 26 planning areas and 3 companies submitted partial rankings. A tabular display and a detailed analysis of these rankings is located in Appendix D of this SID.

7. The General Public

Private citizen responses totalled 208 as of July 15, 1985. Responses from the general public took many forms ranging from postcards and detailed letters to the submittal of photocopies of scores of business cards containing statements opposing the drilling for oil and gas off the coasts of California. More than half of the citizen responses consisted of hand-written correspondence.

Almost all of the general public responses came from California or from former residents of California. Of the 208 items of comment, 196 originated from California, 2 from Oregon, and one each from Alaska, Arizona, Florida, Hawaii, Illinois, Massachusetts, New Mexico, Ohio, Utah, and Washington.

8. Congress

Four letters of comment were received from members of Congress. Two letters were submitted by 3 and 11 members of the California Congressional delegation, respectively; a third letter came from Rep. Gene Snyder, 4th District of Kentucky; and a fourth letter was received from Rep. W. Henson Moore, 6th District of Louisiana.

B. Geographic Distribution of Responses

1. Federal Agencies

Virtually all letters from Federal Agencies originated from headquarters offices in Washington, D.C. The single exception is a letter that came from the

U.S. Coast Guard, 12th Coast Guard District Office, Government Island, Alameda, California.

2. Governors

A maximum of 24 coastal State Governors can be represented, including Hawaii. Of these, the Governors (or their representatives) of 23 States provided comments on the Draft Proposed Program. No response was received from Pennsylvania.

3. State Agencies

Letters received from State Agencies came from 3 of the 4 OCS regions: Atlantic, Gulf of Mexico and Pacific. State legislators from both the Pacific (California) and the Atlantic region were most heavily represented among State Agency submittals. The following is a breakdown of letters received from State Agencies by region:

Atlantic	-	7*
Gulf of Mexico	-	1*
Pacific	-	7
Alaska	-	0

4. Local Governments

All responses from local governments came from the Pacific region and all were from jurisdictions within California.

5. Environmental and Other Interest Groups

Three of the responses from environmental and other interest groups were national in scope. The 18 letters received from State, regional, and local organizations and chapters came most frequently from the Pacific region, especially

*One letter from Florida is included in both regions.

California. The following breakdown of letters received from environmental and other interest groups does not include responses from organizations whose comments are deemed national in scope:

Atlantic	-	4*
Gulf of Mexico	-	4*
Pacific	-	13
Alaska	-	0

* Three letters from Florida are included in both regions.

6. The General Public

Comments from the general public came overwhelmingly from the Pacific region and specifically from California in a disproportionate majority. Comments received from non-coastal States usually expressed concern for drilling off

California's coast rather than off other coastal States. A few commenters identified themselves as former California residents. Two responses from non-coastal States expressed a general concern but indicated no particular regional concern. The following breakdown of comments by region shows the high frequency of responses from the Pacific region:

Atlantic	-	2*
Gulf of Mexico	-	1*
Pacific	-	203
Alaska	-	1
Non-coastal/no regional preference	-	2

* One letter from Florida is included in both regions.

C. Summary

The States in the Pacific region, especially California, provided the largest number of responses. The Pacific region accounted for the largest proportion of comments in three of the four comment categories where the analysis of responses in a regional context can provide a measure of public sentiment towards the OCS leasing program. These include responses from local governments, environmental and other interest groups, and the general public where the Pacific region accounted for 100 percent, 72 percent, and 98 percent of the responses received in these categories, respectively.

III. Summary of Comments by Respondent Category

This section is a summary of the significant issues and key concerns contained in the comment letters. Organization of this section is by major groupings of commenters. These include Federal Agencies, Governors, State Agencies, local governments, oil and gas industry and associations, environmental and other interest groups, general public, and Congress.

A. Federal Agencies

Comments were received from principal Federal Agencies involved in the OCS process. Comments ranged from a brief Department of Defense (DOD) letter, requesting a format change for DOD use areas, to a detailed (4 page letter plus 20 page attachment) set of comments from EPA focusing on numerous key topics. Topics in the EPA submittal included OCSLA section 19 considerations; size, shape, and location and timing of lease sales; 5-year program flexibility; program implementation; and economic analysis. Agencies submitting specific comments included the Department of State (precision of planning area descriptions), the U.S. Coast Guard (navigation concerns, shipping lanes, and traffic separation schemes off California), and National Aeronautics and Space Administration (corrections to NASA Operations Zone descriptions). A brief summary of principal comments by Federal Agencies follows.

1. Department of Defense (DOD)

To facilitate identification and resolution of specific potential conflicts during the presale process, DOD suggested that DOD use-areas should be more prominently displayed in the 5-year program.

2. Department of Energy (DOE)

Comments expressed by DOE focused on subarea deletions, lease sale timing flexibility, minimum bid changes and enlarged tract sizes, and the economic analysis.

- DOE does not "believe that any subarea should be deleted from consideration until an adequate evaluation has been made of the oil and gas resource potential of the area. If a subarea is deleted prior to the time an adequate resource assessment is performed, the Secretary's ability to design a leasing schedule so as to obtain the proper balance called for can become extremely difficult." The comments further state that "if several subareas in a planning area are proposed for deletion, the number of combinations of deletions that would have to be assessed quickly becomes unmanageable." ". . . once a subarea is deleted from consideration, it will be exceedingly difficult to have it later reinstated for consideration, even though evidence is unveiled that the resource potential is dramatically greater than supposed at one time." DOE urged the Secretary to consider all areas in a planning area at the prelease planning stage and stated that there are several steps later in the leasing process where the deletion issue can be resolved with respect to a particular subarea.

- DOE supports the provision to accelerate sales in areas of higher value and/or higher interest, and urges the Secretary and MMS to keep the public fully informed from the time the possibility of an accelerated sale is first considered.

- Concerning minimum bid, DOE supports any changes designed to encourage exploration in frontier areas and in areas about which geological information is sparse. DOE believes that stability in the leasing program and from one 5-year program to the next, is highly desirable.

- DOE's comments expressed concern over the assumptions about future world oil prices used in the analysis which are based on Data Resources, Incorporated (DRI) projections. Their comments suggested that MMS plan to incorporate a range of oil price projections from the National Energy Policy Plan, 1985, to provide greater sensitivity of the rankings to changes in oil price growth rates. They commented that it would be useful to illustrate how changes in assumptions about resource estimates, probabilities, and costs may affect the ranking of planning areas, if at all.

3. Department of State

The State Department comments concentrated on the international aspects or implications of the OCS leasing program and on ensuring that the 5-year program process reflects the U.S. positions on its maritime boundaries and on the extent of maritime jurisdiction generally. They commented that it would be useful to have their mapping experts be consulted on specific geographic descriptions of the planning areas prior to distribution of the Proposed Program and draft Environmental Impact Statement. The State Department's comments provided revised planning area descriptions for these planning areas: North Atlantic, South Atlantic, Straits of Florida, Western Gulf of Mexico, Washington-Oregon, and Chukchi Sea.

4. Department of Justice

Comments from the Justice Department identified two issues of possible competitive concern, first submitted in its August 21, 1984 letter: (1) whether the proposed accelerated rate of leasing would affect competition in the lease market so as to reduce the likelihood that the government will receive fair market value for the leases; and (2) whether the Proposed Program would lead to increased concentration in the ownership of low-quality crude oil reserves in PADD-V. Their August 21, 1984 letter stated that a careful analysis of the first two years of the current 5-year plan should be conducted in order to evaluate the first concern.

Based on material supplied to the Justice Department by the Department of the Interior since their earlier letter, they "currently see no competitive problems arising from the Proposed Program." Their comments state that ". . . to the extent that accelerated leasing may be a factor, the Proposed Program slows down somewhat the rate of leasing and, by using a 'promising area,' rather than areawide approach, limits the number of units offered while maintaining a high level of flexibility, and thus tends to ameliorate any possible concern."

5. National Oceanic and Atmospheric Administration (NOAA)

NOAA's comments focused primarily on the changes proposed for oil and gas leasing off Alaska. Their comments expressed support, with some modification, for the triennial pace of leasing in some Alaska OCS areas, and agreement with the non-scheduling of some areas. Concerns included the size of some planning areas and the ability to fill environmental information needs in time for scheduled sales.

The following are key points made in comments from NOAA:

- Concerning focusing on promising acreage, the early definition of geological structures in the presale process would allow the leasing process to achieve the goals of offering the most promising acreage and of identifying the lease area as precisely as possible.

- The triennial pace of leasing allows enough time to acquire exploration information from a previous sale to generate interest for the next sale. Longer periods may be warranted by delays in exploration, insufficient environmental information, and for major additions of new acreage to a sale area.

- The acceleration of leasing in Navarin Basin, Beaufort Sea, North Aleutian Basin, and St. George Basin should be approached cautiously. Some of these areas have little or no history of petroleum development, no discoveries, and an uncertain production outlook.

- Environmental study needs to be addressed early in the sale planning process. Some areas may require a 5-year lead time. To ensure that frontier areas, such as Alaska, are not adversely affected, DOI should create a "Supplemental Studies" plan for frontier-sale areas to augment the current studies plan.

- The DPP offers certain sales too early for the environmental studies effort to be completed by the exploration stage. For example, the environmental studies program in Shumagin and Chukchi Sea planning areas are out of step with the proposed schedule. For other planning areas the studies programs are adequate for portions but not all of the planning area.

- Several Alaska planning areas have vast amounts of continental slope and deep-ocean basins that may be beyond foreseeable technology and economics. These areas should be examined carefully in the studies program. Decisions on offering tracts should be contingent on studies results.

- The Proposed Program should examine the benefits of creating more focused leasing in planning areas off Alaska. Consider special treatment of the deep-ocean basins in St. George Basin, Beaufort Sea, Gulf of Alaska, Kodiak, and Shumagin planning areas.

- Alaskan areas present problems due to the presence of ice, the remoteness, pristine nature, and subsistence use of the areas. These factors should receive treatment in the Proposed Program equal to that of coral reefs.

- The estimation of social cost in the calculation of net social value based on water column primary productivity is inappropriate and misleading. The estimation should consider the sum of entities and processes governing the production of organic matter and yielding species of high economic, social, and aesthetic value.

- The California planning area reconfigurations will allow the more hydrocarbon-rich southern basins to be considered independently, facilitating more intensive conflict resolution efforts in the Central and Northern planning areas.

- If accelerated leasing occurs in California, the environmental review process should be appropriately intensified.

6. Department of the Navy

The Department of the Navy letter acknowledged their participation in the preparation of the Defense Department's response and that they provided comments at the April 1985 meeting of the OCS Policy Committee.

7. United States Coast Guard (USCG)

U.S. Coast Guard reiterated comments in their letter of September 4, 1985. In their comments, they expressed concern that "conflicts which may arise when leases are granted in and near existing and potential shipping lanes" was not given adequate attention in the Draft Proposed Program. They expressed concern that the resolution process for such conflicts is of sufficient importance to be addressed explicitly in the 5-year program. Their comments stressed the importance of interagency cooperation in effectively applying the statutes to resolve potential conflicts, citing the Central California planning area as an ideal opportunity for such cooperation.

The Coast Guard comments emphasized their preference not to be placed between lease holders as an arbitrator of lease rights in situations where the primary basis for adjusting a presently safe routing system is not navigation safety. The Coast Guard suggested that such contests between lease-holders' can be settled more equitably through a long term leasing program which coordinates areas of restricted lease sale with a scheduled system-wide adjustment of sealanes. The Coast Guard comments concluded by recommending a series of points for further discussion on long-term planned adjustment of designated routing systems off California.

In a second letter from the Coast Guard, 12th Coast Guard District in California, they commented on study results that have identified major vessel traffic routes off the coast of Central California and the need to establish vessel routing measures in the area. The comments contained enclosures which identified proposed changes to the present traffic routes and the status of the proposed changes. Their comments further stated that any leasing activity must recognize navigational safety and vessel routing measures as a limiting factor in offshore development.

8. U.S. Environmental Protection Agency (EPA)

Comments from EPA were extensive and detailed. General comments from EPA focused on the following key points:

- EPA believes that MMS should take a broader view of productivity than the approach used in the DPP of defining "relative marine productivity" solely as "primary productivity." They expressed concern that the analyses of relative environmental sensitivities of OCS planning areas do not seem to account for ecosystem function.

- EPA supports the option to "offer promising acreage."

- Regarding planning area configuration, EPA pointed out that the difference in oceanographic conditions between Santa Maria Basin and the Santa Barbara Channel is considerable. They requested that the Proposed Program provide more detailed discussion of the pros and cons of incorporating the Santa Maria Basin within the Southern California Planning area. They also suggested including a section 18 analysis comparing the two planning area scenario off California in the current program with the three planning area scenario proposed in the DPP.

- EPA recommended that the range of alternative leasing schedules presented in the SID be widened to include a leasing schedule which provides longer intervals between sales in certain areas where triennial sales are now proposed. Examples included basins where environmental monitoring results from earlier sale activity is not yet available, but could be useful in designating later sales or in developing the permits to better regulate drilling activity; planning areas where risks associated with oil and gas development are especially high, such as severe operating environments associated with some Alaskan basins, or where oil and gas resource estimates and industry interest are relatively low and biological resources are exceptionally high.

- EPA expressed concern that "Accelerated sales could . . . cause planning disruptions and add uncertainty to the DPP," and "That already tight timeframe for issuance of [National Pollutant Discharge Elimination System] permits would be further compressed by the acceleration of a lease sale." Their comments also stated that altering the "diligent development" requirements incorporated in the Notices of Sale might serve the same purpose as the flexibility provision for attempting to deal with sudden changes in oil supply.

9. National Aeronautics and Space Administration (NASA)

Two letters were submitted by NASA. The first letter requested changes to the descriptions of NASA Operations Zones for the Mid-Atlantic and Southern Atlantic planning areas. The second letter provided a description of the NASA Operations Zone for the South Atlantic planning area to replace and clarify the description provided in their first letter.

B. Governors

Generally, the Governors were supportive of OCS leasing and endorsed the Secretary of the Interior's efforts to resolve conflicts in the prelease process by engaging in early and frequent consultation and by seeking to generate a consensus on broad issues of concern. However, responses from the Governors showed a broad range of concerns from requests for clarification of specific points to requests for the deletion of entire planning areas from the leasing schedule. The following is a State-by-State synopsis of the Governors' significant comments.

1. ALABAMA

- Seeks the sharing of all revenues generated from Federal leases totally or partially in a State's 8(g) area.

- Timing and location of Central and Western Gulf of Mexico sales is reasonable, but timing and location of sales elsewhere is insufficient to contribute to the discovery of new reserves or to continue the inventory of resources. Requests flexibility to accelerate sales in the Eastern Gulf in the event of a major discovery.

- The proposed presale process is reasonable.

- In areas of high petroleum potential, such as an 8(g) area of a coastal State, the minimum bid level should be higher. Expansion of the block size in the 8(g) area of Alabama is not acceptable.

- All blocks in Alabama's 8(g) area are assumed to contain common pools and common structures unless proven otherwise; structure determinations made in the 5-year program should be consistent with the State's position on this issue.

- Seeks lease stipulations or unitization agreements between the States and MMS for blocks in the 8(g) areas to handle potential drainage of hydrocarbons.

- Wants MMS lease stipulations to require environmental and water quality regulations that are consistent with those of the State.

- No specific subarea deletion requests, but seeks favorable special consideration for resolution of any and all conflicts on blocks with high resource potential.

2. ALASKA

- The presale process focusing on promising acreage has not significantly reduced the size of the proposed sale areas. Alaska prefers a return to a tract selection process or some analogous focused leasing process to determine the size of proposed sale areas.

- Supports a maximum of three Federal sales on an annual basis off Alaska, provided that no more than 12 sales occur within any 5-year period. (DOI has proposed 15 sales at the rate of no more than three per year in the Draft Proposed Program.)

- Is concerned with the flexibility provision; wants to know more about the provisions and the specific criteria or regulations to be used in the decision to impose the provision.

- Remains strongly opposed to the timing of the scheduled sale in the North Aleutian Basin; asks that no sale occur in the area until at least 1994 in concert with the Bristol Bay Management Plan and with the State's own 5-year oil and gas leasing plan. Recommends removing the two North Aleutian Basin sales from the Draft Proposed Program.

- Sale-specific concerns should be handled during the individual lease process rather than during the development of the 5-Year OCS Leasing Program.

- Subarea deletion requests: Area near Unimak Pass, tracts near the Pribilof Islands, area within 12 miles of the Yukon Delta, and traditional subsistence hunting areas in proximity to Pt. Barrow.

3. CALIFORNIA

- The Governor expressed his continued commitment to a tract-by-tact analysis of the OCS rather than support for a moratorium for the area contained within the proposed plan.

- The Governor's letter identified several points that were stated in the California Secretary of Environmental Affairs' letter of September 17, 1984. Governor Deukmejian's review of the Draft Proposed Program revealed several points which do not appear to be in the best interests of California nor do they reflect the goals and policies of the State and the local governments in the coastal areas:

  - The Program should provide alternatives to the current moratoria.

  - Sensitive areas should be protected through subarea deletions.

  - Onshore impacts should be fully considered, including effects on local plans, air quality, and coastal infrastructure.

  - Adequate participation of local government in the planning process should be ensured through appropriate size and timing of lease sales.

- The Governor seeks solutions through negotiations based on a good faith effort from all involved parties. Lack of progress on the 8(g) issue was cited as a point of concern.

- In accordance with section 18(c)(1) of the OCS Lands Act Amendments, the Governor solicited suggestions from local governments and other interested parties in California. The responses received by the Governor have been included as five attachments (A-E) with California's comments.

  - Attachments included (A) a summary of comments received by May 2, 1985; (B) a summary of meetings on the Draft Proposed Program; (C) photocopies of the comments received by May 2, 1985; (D) photocopies of the comments received after May 2, 1985; and (E) a summary of local government suggestions for the Draft Proposed Program.

  - The summary of comments received by May 2, 1985 included 7 responses from State Agencies, 35 from local governments, 3 from the oil industry, 19 from organizations, and 304 from individuals.

  - Comments received by California after May 2, 1985, and included, but not summarized, as part of their comment submittal totalled 712. These included 3 responses from State Agencies, 12 from local governments, 2 from the oil industry, 6 from organizations, and 689 from individuals.

4. CONNECTICUT

- Supports all reasonable efforts to further develop domestic energy resources and remains committed to the environmentally sound and economically prudent exploration of the OCS.

- The proposed program strikes a reasonable balance between the environmental concerns of coastal States and the reality of today's oil markets.

- Continues to support the consistency review for lease sales and their potential impacts on coastal area management programs. Seeks DOI's full and continued support of the Environmental Studies Program.

- Supports the concept of OCS revenue sharing . . . to provide for adequate funding in support of coastal zone management activities and State OCS participation.

5. DELAWARE

- Welcomes the policy of triennial sales and the emphasis on consultation and consensus.

- Reiterates the need for reconfiguration of the boundary between the Mid-Atlantic and North Atlantic planning areas. The suggested change would better conform to the geological division between the Baltimore Canyon trough seaward slope and rise and the Georges Bank basin.

- Cites potential conflict with the State's Coastal Management Program, particularly with provisions of the Coastal Zone Act. The law prohibits heavy industrial development and offshore bulk

cargo transfer facilities to be sited within Delaware's coastal zone.

- Believes it is essential that Federal revenues from OCS leasing be shared with coastal states.

- Subarea deletion requests: Submarine canyonheads in the Mid-Atlantic and tracts within 12 miles of Delaware's territorial waters (within 15 miles of the State's coasts).

6. FLORIDA

- Acceleration of sales should be done only after careful consideration is given to all social, economic, and environmental factors. Ample time must be given for close consultation with affected States and local governments.

- Recommends the NASA/DOD Flight clearance zone be permanently removed from the sale area and seeks permanent resolution of military use conflicts.

- Seeks removal of the areas in the Eastern Gulf of Mexico: South of 25° N latitude to 24° N latitude and East of 82° W longitude from the leasing program because of the sensitivity of the area, current conditions, and the lack of environmental studies data.

- Recommends dropping the Straits of Florida and not adding it to the 5-year schedule, citing a previous agreement between Florida and the Department of the Interior not to allow leasing in the area.

- Areas of deferral and actual industry interest should be decided before the draft EIS is released.

7. GEORGIA

- The date for the next South Atlantic lease sale (July 1989) is reasonable.

- The 5-year program appears to accommodate industry's needs while providing ample time between sales so that environmental concerns can be properly addressed.

- No specific subarea deletion requests were stated.

8. HAWAII

- The new and extensive coverage given to social cost analysis is justified.

- The provision to accelerate sales in higher value, higher industry interest areas allows the needed flexibility for MMS to respond to changing conditions.

- Addition of the "Request for Interest" step may save parties involved in the presale process needless time and expense.

9. LOUISIANA

- The Governor's letter commented that Louisiana's concerns about areawide leasing and its potential environmental and long-term economic impacts, and the need for equitable sharing have been disregarded.

- The new 5-year program does not provide for an equal distribution of leasing among OCS regions or for paced development in Louisiana. The comments stated that the Draft Proposed Program places an even greater share of OCS development in the Louisiana and Texas OCS, citing scheduling concessions to all areas of the country except the Central and Western Gulf of Mexico.

- Louisiana asked that specific mechanisms and procedures be incorporated into the new 5-year plan to clarify the emphasis on consultation.

- The Governor's comments noted a continuing acceleration of sales in mature areas and a decrease in sale frequency in frontier areas despite the Congressional intent in the OCS Lands Act Amendments to expedite offshore oil and gas development and to encourage development in frontier areas.

- Louisiana urges reconsideration of the the areawide approach in favor of a system that insures the nation the revenues it deserves from the sale of energy resources.

10. MAINE

- Wants more explanation of the Department's approach to scheduling sales in the Atlantic. Two sales are scheduled in the North Atlantic, but only one sale is scheduled in each of the Mid- and South Atlantic.

- Seeks explanation of how focused leasing will work. Suggests a "middle ground" alternative to areawide and tract selection leasing: forming "interest tracts" by aggregating a number of blocks (for example 100 blocks) into discrete areas for identifying industry interest and conducting environmental analyses.

- Suggests forming a working group composed of DOI, industry, and State representatives to identify and evaluate alternatives to the presale planning process.

- Favors the use of supplemental sales and "flexibility sales"; suggests extending the use of the extra presale step for frontier sales to sales proposed in the North Atlantic.

- Share information gathered in response to a request for industry interest with States, and consult with Governors when deciding whether to proceed with planning a sale.

- Secure agreements with Canada to ensure that both sides can develop oil and gas resources without causing harm to the environment or to the fishing industry that depends on Georges Bank.

- Requests removing the Gulf of Maine from the North Atlantic planning area because of the absence of suitable geology.

11. MARYLAND

- Favors a strong consultative role for the States with resolution of conflicts on a case-by-case basis, and favors a consensus-making approach to consolidate better State-Federal relationships.

- Has no objection to reducing the number of standard sales and adding frontier and supplemental sales to the program.

- Agrees that areas having high resource potential and high industry interest should have top priority; areas of low potential, low industry interest, and areas about which little is known and analyses are few should have a lower priority.

- Supports the proposed presale process including the additional presale step of "Request of Interest" in frontier exploration sales. Such a step should be considered where interest is low due to recent disappointing drilling results.

- Supports the proposal for sufficient flexibility to accelerate sales to meet changing economic conditions.

- Concurs that the minimum bid should be adjusted, at least on a planning area basis, to take care of any contingencies that may arise.

- Tract size is not the most important parameter to maximizing offshore oil and gas discoveries. The MMS needs to explore innovative procedures in frontier areas and in areas of currently disappointing economic potential to optimize the discovery potential.

- Proposes a split presale process: consider using tract selection leasing on nearshore acreage (less than 50 miles from shore) and areawide further offshore (more than 50 miles from shore).

12. MASSACHUSETTS

- Cites two "compelling arguments" against continuing to plan lease sales in the North Atlantic.

  - The high biological productivity of the Georges Bank region makes it environmentally unacceptable to allow oil and gas leasing.

  - Raises the question of whether there is any promising acreage in the North Atlantic, and if there is, how the potential can be documented in the program analysis.

- Supports the overall effort to slow the pace of leasing and to focus on offering areas with promising acreage, but is concerned that two sales are scheduled in the North Atlantic when the area contains little or no promising acreage. Only one sale, at most, is needed in the North Atlantic.

- Lease sale areas should correspond more closely to oil- and gas-bearing physiographic regions rather than the geographic boundaries of planning areas.

- Although focused leasing reduces the acreage from the proposed sale area, large amounts of acreage must still be examined in the environmental review process. The areawide and focused leasing approach is inappropriate for frontier areas such as the North Atlantic.

- Recommends small sales corresponding more closely than in the past to the oil- and gas-bearing physiographic regions of OCS frontier areas.

- Urges working with the oil industry to develop a system for obtaining more reliable information on areas of primary interest to better define sale areas.

- Recommends that DOI solicit industry interest after the DEIS has been released to expose any changes in interest that may occur during the planning process.

- Recommends that DOI and the States discuss any differences that exist concerning a lease sale prior to issuance of the Proposed Notice of Sale (PNS) and that the PNS, when issued, reflect the results of these discussions.

- Expressed concern that the flexibility provision not be employed to circumvent the statutorily mandated planning process of the 5-year program.

- Suggests the need for better information concerning the flexibility provision, supplemental sales, and the acceleration of sales, especially with respect to their implementation and their effect on the administration of the 5-year program.

- The Gulf of Maine contains little or no hydrocarbon-bearing sediment and should be removed from further leasing consideration.

Environmental analysis tied to physiographic provinces points to the elimination of Georges Bank region from the 5-Year Program.

- Remove the area encompassed by the 400-meter isobath and the submarine canyons from further leasing consideration because of the biological significance of the Georges Bank fishery and its role in the Nation's food supply.

13. MISSISSIPPI

- The response from Mississippi acknowledged receipt of the Draft Proposed Program but provided no formal comments on it.

14. NEW HAMPSHIRE

- Due to lack of industry interest in Sale 82, DOI should consider application of an additional presale step before Sale 96 to assess industry interest.

- The 5-year program should include a discussion of the impacts of the October 12, 1984, decision on the United States-Canada Maritime Boundary issue, and the steps to be taken to addresses these impacts. An agreement on international issues should be formally reached before the North Atlantic sale.

15. NEW JERSEY

- Supports exploration and production of OCS oil and gas as long as they are consistent with sound environmental practices necessary for the protection of the State's coastal tourism industry and the State's $1 billion commercial and recreational fishing industry.

- Slower pace of sales is beneficial to New Jersey since it has equal interest in OCS activities in both North and Mid-Atlantic. Slower pace allows better integration and coordination of data from the Environmental Studies Program into the sale process.

- Supports the proposed configuration of planning area boundaries as they pertain to North and Mid-Atlantic planning areas.

- Recommends decelerating the schedule for the North and Mid-Atlantic planning areas to include only one North Atlantic sale in the 5-year program and requests a delay of the next Mid-Atlantic offering. Cites relatively low estimated net economic value of leasable resources, little resource potential in high-value prospects, and absence of industry interest in North Atlantic Sale 82.

- No objections to the location of proposed sales.

- A program of focused leasing, as a subset of the areawide concept along with close consultation with affected States during the process, is acceptable to New Jersey.

- Has no objections to the flexibility provisions of the proposed program, but adequate State consultation must be built into the process.

- Would be willing to explore varying the current per acre bid level and/or expanding maximum tract size if it could be shown that the result would produce economic benefits to the Federal Government, encourage exploration, and provide opportunities for more in-depth environmental analysis.

- Requests deletion of tracts within 50 miles of the State's coast, and within canyon systems having high environmental sensitivity and importance to commercial fisheries. Supports eliminating all tracts within 50 miles off the coast in the Mid-Atlantic and North Atlantic planning areas.

16. NEW YORK

- A change is needed in the way the level of industry interest is identified for lease sales. Suggests soliciting oil versus gas interest and differentiating among interest expressed by small, medium, and large companies to get a better picture.

- Environmental sensitivity figures are misleading as to the environmental importance of a region. Marine productivity calculations show that both Mid- and North Atlantic areas have the highest marine productivity values, but environmental sensitivity figures rank the two regions far lower overall compared to the rest of the regions.

- Argues with the assumptions used to describe the potential loss of tourism and recreation due to oil spills and questions the assumption that losses in one location will be offset by increases in other unpolluted substitute sites. Not all tourists seeking a particular shoreline location may have access to alternative sites.

- Supports the continued separation of the North and Mid-Atlantic regions for planning and lease sale purposes, but seeks access to proprietary data from both regions if needed.

- Continues strong support for OCS Revenue Sharing for coastal States.

- Expressed concern that no oil and gas exploration is taking place in the Atlantic region, and that no new significant discoveries are occurring to offset declines of production in the Gulf of Mexico and Alaska.

- Suggests the need to examine alternative mechanisms to ensure that some level of exploratory activity continues. Innovative leasing systems, consortia, and government industry cooperative research should be examined as a means to encourage exploration, particularly in frontier areas.

17. NORTH CAROLINA

- Expressed concern that before the Straits of Florida is officially approved, a thorough feasibility analysis, including environmental studies and resources, assessment, should be conducted by the Department of the Interior.

- The number and pace of proposed sales is reasonable.

- Expressed comments concerning annual Supplemental Sales.

  - Raised the question whether the Department has the statutory authority for the proposal to hold annual Supplemental Sales.

  - If DOI has the authority for such sales, no block should be offered unless it has gone through an EIS process within the last 5 years.

  - Consider a "Request for Interest" step in the prelease process.

  - Before holding Supplemental Sales, develop and adopt specific guidelines and regulations pursuant to Section 18(f) of the OCS Lands Act.

- Endorses the focusing on promising acreage concept as a sensible move away from the areawide concept. Suggests that the USGS or other appropriate Federal Agency should be encouraged to intensify efforts to define more precisely specific areas within OCS regions that would be most attractive for leasing.

- Raised questions concerning the flexibility provisions.

  - Why is the flexibility provision part of the 5-year program when Section 18(e) of the OCS Lands Act allows for this type of flexibility already?

  - Why limit areas under consideration for such acceleration to just the eight mentioned in the inquiry?

  - Is it appropriate for consideration in other areas as well?

- Objects to lowering the minimum bid level, but would not object to raising it. DOI should strive to get the highest return in all situations.

- Has supported and continues to support some form of OCS revenue sharing.

- Expanding the size of particular tracts beyond the present limit of 5,760 acres to comprise a reasonable economic unit may be appropriate in some situations.

- Expressed concern with the concept of net social value and the underlying figures used to support the cost figures and the benefit figures. Recommends including infrastructure costs in the analysis.

- Recommends that productivity and sensitivity be analyzed by broader and perhaps more meaningful indicators.

- Endorses the subarea deletion concept. Areas that can be excluded without much controversy should be deleted from the 5-year programs.

  - Such areas might include shipping lanes, submarine lanes, ocean disposal sites, offshore national defense areas, NASA flight zones, National Marine Sanctuaries and areas affected by international boundary disputes.

  - Consider deleting the area shoreward of the 200-meter isobath off North Carolina.

  - For adequate protection of the Monitor Marine Sanctuary, designate a buffer zone which would exclude leasing.

  - Exclude two sites being analyzed and considered for the national marine sanctuary program. The inner shelf (Ten Fathom Ledge) is a 135 square mile site centered about 17 miles south of Cape Lookout, N.C., and the outer shelf (Big Rock) located on the shelf break is about 36 miles offshore and is approximately 36 square miles in size.

  - Canyonhead areas should be excluded.

  - Conduct studies on the outer shelf and edge live bottom complex to determine candidate sites for exclusion.

18. OREGON

- Favors a thorough examination of the oil and gas development potential of the offshore lands and gives qualified approval for retaining Oregon in the Draft Proposed Program.

- Approval of any postlease activities will be reviewed for consistency with Oregon's Coastal Management Program. Only include areas in the 5-year program for which consistency certifications will be forthcoming.

- Suggests that DOI and the States of Oregon and Washington be invited to participate in a new working group for the Pacific Northwest. The group would determine whether OCS areas off the two States should be placed on the 5-year program and would design an environmental studies program.

- Suggests that MMS establish an Environmental Studies Field Office in Newport, Oregon (Mark O. Hatfield Marine Science Center), to coordinate and conduct resource assessments and social, economic, and environmental studies off the Pacific Northwest coast.

- Suggests that MMS begin collecting baseline data off Oregon and Washington by holding a conference and workshop to update BLM's 1977 recommendations from the conference on research and inventory needs for offshore oil and gas development.

- Expressed disagreement that there will be "negligible" social and economic effects on the Oregon coast from offshore development and took issue with findings which characterize Oregon's marine environment as of relatively low biological productivity and of relatively low susceptibility to damage from spilled oil.

- Favors the sharing of Federal OCS oil and gas revenues with coastal States to help mitigate the otherwise unacceptable social and economic effects of offshore leasing on coastal communities.

- General conclusions contained in the social, economic, and environmental sections of the Draft Proposed Program would not meet the requirements of the Oregon Coastal Management Program or the Council on Environmental Quality's requirements for completeness of information or for a worst case analysis.

- Expressed concern that 3 years is not adequate time for MMS to identify, fund, conduct, and analyze the studies necessary to support a lease sale. Suggests the need to begin studies off Oregon and other frontier areas before making the final decision on which planning areas to include in the 5-year program.

- Requests deletion of the advancement (acceleration) provision from the proposed 5-year program.

- Believes that planning areas are too large and are based on political boundaries rather than geological ones. Planning areas should only include geologic basins of high hydrocarbon potential and of high industry interest, but should exclude subareas with significant fisheries. Asked that the areawide concept be abandoned.

- Asked for continuation of efforts to develop more accurate oil spill projection models for impact assessment and contingency planning and to implement these computerized systems for the Oregon coast.

- Proposed boundary of the planning area off Oregon is not acceptable. Oregon is willing to accept a planning area with a western boundary coincident with 125° west longitude provided that this planning area excludes subareas of Heceta, Stonewall, and Perpetual Banks.

19. PENNSYLVANIA

- No response received as of July 12, 1985.

20 RHODE ISLAND

- Supports "focused" areawide leasing as a reasonable compromise between an accelerated program and the tract selection approach; endorses the triennial cycle of sales; and withholds support for the "flexibility" provision until the "national emergency" triggers for accelerated leasing are more clearly defined.

- Seeks clarification concerning when pre-call consultation would begin, how formal it would be, and how it would affect the Call and subsequent presale milestones. Suggests considering adding a pre-call "Request for Interest" in planning areas of unproven potential, such as the North Atlantic.

- Recommends that special consideration subareas such as submarine canyons and canyonheads, or "no surface occupancy" zones designated by the Department of Defense be dealt with on a sale-by-sale basis.

- Wants to pursue a change in the Department's current rule on the sharing of proprietary data and to be admitted to membership on both the North Atlantic and Mid-Atlantic Regional Technical Working Groups as a full voting member of each.

- Endorses establishing different minimum bids for different planning areas as an incentive to get industry interested in the North Atlantic; recommends testing the idea of a work commitment/fixed royalty bidding system in the Hudson Canyon area and in other areas of marginal industry interest.

- Recommends an analysis of social costs incurred by State and local Governments in planning for OCS development and an analysis of infrastructure costs, noting that the cost/benefit ratio for many communities is lopsided.

- Reiterated its recommendation that the Department continue negotiating with all interested parties when proposing to open relatively sensitive areas to oil and gas leasing, or when proposing areas where conflicts are likely to arise from other users of the OCS or the waters above it. Recommended frequent meetings to work out traditional problems of spatial pre-emption, physical alteration of the seafloor, gear loss and other likely sources of conflict.

- Continue funding for the Environment Studies Program and ensure that leasing, exploration, and production do not outpace the Program's environmental research advances.

21. SOUTH CAROLINA

- Strongly encourages the development of specific guidelines for implementation of the program's "acceleration provision."

- Asks that a comprehensive analysis be prepared for marine productivity and environmental sensitivity similar to that for the economic analysis. The current marine productivity and environmental sensitivity analysis is not as sensitive to variation as it should be.

22. TEXAS

- Is committed to a "fast track" negotiation process to enable the States and the Department of the Interior to speedily resolve 8(g) concerns.

- Favors the emphasis on early and meaningful consultation with States, local governments, and other interested parties.

- States that the Federal Government is required to identify and offer those areas of highest promise in other OCS planning areas as well as in the Gulf of Mexico.

- Opposes areawide leasing, but is having difficulty discerning the practical difference between "areawide" leasing and the leasing of "promising acreage."

- Expressed concern that many of the deficiencies of the areawide leasing program may unintentionally be carried forward into the new 5-year program through inclusion of all "promising acreage" in the Central and Western Gulf of Mexico.

23. VIRGINIA

- It is essential to protect Virginia's coastal resources, including the Atlantic Ocean off the coast, Chesapeake Bay and its estuaries, Hampton Roads, Eastern Shore, and Virginia's beaches, wetlands, and fisheries.

- Supports proposed planning area configurations and boundaries since the changes do not affect Virginia and are more site specific and they more clearly define areas to be considered than do current boundaries.

- The number and pace of sales is sufficient to allow adequate assessment of each sale and gives industry enough opportunity to explore these frontier areas.

- Supports annual sales in Central and Western Gulf of Mexico and triennial sales elsewhere.

- Agrees with the proposed presale process.

- Virginia is not affected by the flexibility provisions, but views the plan as a sound one.

- Supports revenue sharing from oil and gas leasing with coastal States.

- Since special considerations, i.e., recovery of minerals other than oil and gas, have been a vital part of plans for the proposal of the sale off Oregon and Washington in 1991, it follows that circumstances could dictate special considerations in other lease sales elsewhere.

- Requests deletion of areas within 50 miles of the coastline, an area which to date has not elicited industry interest.

24. WASHINGTON

- The draft program document seriously underestimates the social costs of leasing in the Washington-Oregon planning area.

- The program as presented is unbalanced, and to that extent unacceptable, because it purports to offer the entire Washington offshore for leasing, including tracts that are beyond the continental shelf and those well beyond the limits of drilling technology, both current and near-term future. Lease offerings should be limited in area to the acreage contained in the promising geologic structures.

- Recommends holding field hearings in Washington State before the Department of the Interior submits the 5-year program to the U.S. Congress.

- Washington State considers the areawide leasing approach to be flawed. Focused leasing is a step in the right direction, but it does not go far enough. A process is needed that recognizes that there are coastal and marine areas that should be protected.

- Among the most important and immediate tasks is the initiation of a comprehensive environmental studies program. The Department of the Interior should sponsor a symposium to determine the baseline information needs relative to the development of OCS oil and gas resources in the Washington-Oregon planning area. State resource agencies should have a role in conducting environmental studies when it is clear that they have the expertise.

- The MMS should establish an OCS environmental studies field office in Washington to facilitate the exchange of environmental information with universities and State and local governments.

- Potential multiple-use conflicts can best be handled at the earliest possible stage, i.e., prior to leasing, under the framework of Washington's federally approved coastal zone management program. Local jurisdictions have responsibility for administration of their shoreline program. Exploration and development activities will need to be consistent with the State and local coastal zone management plans.

- As seismic surveying increases along the coast in anticipation of leasing, there will be a need to improve coordination between Federal and State permitting procedures. Washington's Department of Ecology has permitting authority for seismic surveys in State marine waters. Washington's comments suggest the need to update the 1982 memorandum of agreement.

C. State Agencies

Numerous comments received from State Agencies expressed appreciation for receiving copies of the Draft Proposed Program but provided no formal comments. A letter from K. Leroy Irvis, Speaker of the Pennsylvania House of Representatives expressed concern for the environmental effects offshore drilling may have on beaches and wildlife and stated his support for any proposal which will hold those drillings to a minimum and for proposals which will provide greater safeguards for the environment. South Carolina House of Representatives Minority Leader, Alex Harvin, III, stated his commitment to working toward a consensus on leasing issues, both in developing a new program and in planning for individual lease sales.

A letter from California 35th District Assemblyman, Jack O'Connell included a reference to California Assembly Joint Resolution No. 42. The resolution requests deletion from the 5-year program of all offshore areas adjacent to State-owned tide and submerged lands where oil leases are currently prohibited and all areas offshore of California north of the seaward extension of the Mendocino-Sonoma County Line and requests the Governor to make that recommendation to the Secretary of the Interior.

Assemblyman O'Connell emphasized concern about the pace of leasing proposed for California, stating that more leasing in the Santa Barbara Channel will create greater burdens for more onshore facilities to handle the additional production. He suggested removing the proposed Southern California area from the current 5-Year Plan until all existing leases have been explored thoroughly enough to indicate how much oil will be processed in Santa Barbara from those leases. He further said that leasing should not occur off Northern California, except in a national emergency, citing the unacceptable risks to economic, social, human, and natural environments far in excess of the projected value of the oil resources. He stated that California is doing more than its share in developing OCS oil and gas resources and recommended that California not be included in the 5-year program.

The Majority Leader of California's State Senate, Barry Keene, opposed inclusion of sensitive north coast areas noting that exploration risks far outweigh potential benefits. The letter says that the high risks combined with low hydrocarbon potential justify special consideration for the north coast.

Key concerns were expressed in letters from 11 members of the California Senate, the California Department of Justice, and the California Coastal Commission. Highlights of each letter follow.

Senate, California Legislature

- Senate members oppose the Draft Proposed 5-Year Program believing it fails to strike a reasonable balance among environmental protection, coastal resource management, and oil and gas development.

- They claim that "slowing down leasing offshore California appears dubious in light of the new leasing brought about by the addition of a third OCS planning area and the use of 'supplemental' sales."

- Acknowledging that three California planning areas may be appropriate, the reconfiguration is objectionable. They recommended:

  - retaining the current Southern California planning area. They noted that merging the Santa Maria Basin and Santa Barbara Channel and other oil producing areas further south exacerbates the problem of large planning areas.

  - designating the Santa Maria Basin, from Point Conception to the Santa Maria River, as the new Central California planning area.

  - including the Santa Cruz, Bodega, Point Arena, and Eel River basins in a Northern California planning area and deleting the area from the 5-year program. They cite high environmental and economic risk and low resource potential as justification for special consideration for the four basins.

- They recommended deleting from the 5-year program tracts off California in their proposed southern and central California planning areas that were determined to be of high risk and low value, including

  - all tracts within the Point Reyes-Farallon Islands, and Santa Barbara Channel Islands National Marine Sanctuaries;

  - all tracts within and immediately adjacent to Santa Monica Bay;

  - all tracts within the access routes to the Ports of Los Angeles, Long Beach and San Luis;

  - all tracts within a 6-mile buffer zone around Catalina Island; and

- all tracts within a 12-mile buffer zone from the San Diego County/ Mexican boundary to Newport Beach in Orange County.

- They strongly objected to the flexibility provision citing the Department of the Interior's unqualified discretion to accelerate leasing in response to favorable economic conditions.

California Department of Justice

- Concern was expressed that the Draft Proposed Program does not reflect a reduction in the pace of leasing offshore California, citing 5 regular sales and potentially 5 supplemental sales.

- Comments included a request for smaller planning areas, reiterating a request made in their August 23, 1984 letter.

- California's Justice Department believes that a return to the far more focused approach associated with the tract nomination procedures is desirable.

- Comments recommend formalizing the consultation procedures and providing guidelines for tract deletions or imposition of stipulations to which Interior would be bound.

- The letter expressed concern about the flexibility provision, questioning whether it violates section 18(e) of the OCS Lands Act and how it would be implemented assuming legality of the provision.

- The Department expressed concern that supplemental sales violate section 18(a) because they fail to specify as precisely as possible which areas would be offered and when such leasing would occur. They recommended deleting supplemental sales from the 5-year program proposal.

- Concern was expressed that DOI needs to assume the responsibility for addressing the question of transportation of oil and gas along California's coast and to deal affirmatively with the problem.

- California's Department of Justice has suggested that the analysis to support the balancing considerations is not appropriate within the meaning of section 18(a)(3).

- Concluding comments state that the Draft Proposed Program ". . . must be seriously modified both to narrow the size of the areas to be included on the program and to slow the pace with which they are offered."

California Coastal Commission

- California Coastal Commission comments covered continuing concerns with the size, timing, and location of past and proposed lease sales off the California coast.

- The Coastal Commission objected to the flexibility concept. They noted that it would conflict with the goal of defining sale areas as precisely as possible and would not provide for Congressional review of the Department's decisions.

- They recommended deletion of tracts north of the Santa Maria River in Central and Northern California, deferral of tracts in the Santa Barbara Channel, deletion of some tracts off the Los Angeles and Ventura border, deletion of some fisheries tracts south of Santa Rosa Island, deletion of tracts offshore San Diego, deletion of tracts within six nautical miles of Catalina Island, and deletion of tracts within Marine Sanctuaries and Federal oil and gas reserves.

- Comments stated their objection to increasing California planning areas from two to three, citing Santa Maria Basin ecological dissimilarities with the Southern California planning area and the imposition of additional planning burdens on already strained local governments.

- The Commission expressed concern with DOI's broad analysis of impacts to marine life, navigation, fisheries, oil spills, socio-economics, as well as conflicts with other users such as deep sea minerals extraction and military operations.

- The Commission recommended that DOI require oil transportation by pipeline instead of tankering in all areas of the Pacific coast.

D. Local Governments

Responses from local governments included 29 responses received directly by DOI. Responses from local governments, incorporated in the attachments to California's Governor's letter, totaled 47. Considerable duplication of comments received by DOI and the State of California exists. Of the 29 responses received directly by DOI, only 3 could not be found among the comments attached to the California Governor's submittal: City of San Diego, Orange County, and City of Santa Monica.

Two States in addition to California submitted comments from local governments and other constituent groups as attachments to Governor's letters: Florida and Oregon. Where appropriate in this section these letters are summarized.

Responses submitted by local governments represented most coastal county jurisdictions and many of the major individual coastal cities and communities in California. Special jurisdictions such as associations in this section of governments and air quality districts also submitted responses.

The local government responses generally expressed opposition to offshore drilling, albeit to varying degrees. A common means for expressing opposition was through the adoption of resolutions by the various governing authorities. For example, resolutions were submitted opposing adoption of the Draft Proposed

5-Year Program, opposing offshore leasing, favoring continuation of the moratoria, and favoring the deletion of specific subareas from leasing consideration. Such opposing resolutions were submitted by the following jurisdictions:

1. Association of Monterey Bay Area Governments
2. City of Fort Bragg
3. City of Laguna Beach
4. City of Morro Bay
5. City of Pacifica
6. City of Pismo Beach
7. Marin County
8. Mendocino County
9. Monterey County
10. San Luis Obispo County
11. San Mateo County
12. Santa Cruz County
13. Sonoma County

Although nearly all comments from local governments expressed reservations concerning the Draft Proposed 5-Year Program, the response from the City of Eureka favored the leasing and exploration of California's North Coast. The City of Eureka's mayor and city council unanimously favored not extending the current moratorium on offshore drilling off northern California's coast.

The remainder of this summary of local government's responses presents a brief synopsis of the principal comments received directly by the Department of the Interior and also includes those responses submitted with the Governor's comments from California, Florida, and Oregon. The summary is organized by State and within States by jurisdiction, i.e., county, city, and special district.

1. California

a. Counties

Del Norte County

The Draft Proposed Program does not adequately consider the balancing of economic benefits and environmental risks. The analysis does not adequately address impacts on fisheries, navigation, and marine mammals and does not contain provisions for considering economic impacts at a regional or local scale. Concern was expressed that DOI has no intention of addressing local and regional concerns, citing a lack of documents being made available to the potentially affected local governments.

Humboldt County

Commercial fishing and tourism are important to the economic base of Northern California and should be protected. As recently as October 1984, the Humboldt County Board of Supervisors recommended that there be no leasing north of Morro Bay.

Los Angeles County

The Department of Regional Planning has no objection to the proposed procedures or schedule, but recommends that review times on lease sales be extended as much as possible in order or accommodate limited local government resources. Drilling within visual range or having a trajectory impacting County beaches, recreational facilities, or natural resources poses high risks. In particular, Santa Catalina Island, Marina del Rey/Ballona wetlands, Malibu coastline, Los Cerritos wetlands, and County beaches have high environmental and economic values that could be impacted by oil spills, drilling activities, boat traffic, and sediment transport. OCS air quality impacts would be contrary to the region's regulatory, economic, and environmental objectives.

Marin County

The Board opposes adoption of the Draft Proposed Program for the following reasons: areawide leasing and the streamlined prelease process does not permit adequate consideration of local land use priorities, commercial fishing conflicts, and local agency inputs; the draft does not adequately consider fisheries, navigation, sealane, and military use conflicts; and leasing impacts on existing local economies are not considered.

Mendocino County

The Board opposes adoption of the Draft Proposal Program for the following reasons: areawide leasing and the streamlined prelease process does not permit adequate consideration of local land use priorities, commercial fishing conflicts, and local agency inputs; the draft does not adequately consider fisheries, navigation, sealane, and military use conflicts; leasing impacts on existing local economies are not considered; the Draft does not consider the relative marine productivity and environmental sensitivity of the planning areas; the Draft does not consider the equitable sharing of developmental benefits and environmental risks; and the Draft does not consider the laws, goals, and policies of California.

Monterey County

The Board opposes adoption of the Draft Proposed Program for the following reasons: areawide leasing and the streamlined prelease process does not permit adequate consideration of local land use priorities, commercial fishing conflicts, and local agency inputs; the draft does not adequately consider fisheries, navigation, sealane, and military use conflicts; leasing impacts on existing local economies are not considered; the Draft does not consider the relative marine productivity and environmental sensitivity of the planning areas; the Draft does not consider the equitable sharing of developmental benefits and environmental risks; and the Draft does not consider the laws, goals, and policies of California.

Orange County

Orange County offered no substantive comments, but requested to receive copies of guidelines on the 5-Year Program flexibility provisions when they become available.

San Diego County

It is unreasonable for Federal, State, and local agencies to repeatedly review and comment upon proposed lease sales for areas that have been previously deleted. This process is a waste of staff resources which are in short supply at the local level. There should be a one-time review for each planning area when governors and local agencies would work with DOI and Federal Agencies to identify permanent deletions and avoid the use of Congressional moratoria.

Tracts in the nearshore San Diego area are sensitive for military and environmental reasons and have low resource prospects; they should be deleted. The 3-year lease sale interval is a positive step in slowing the pace of offshore leasing, but the acceleration provision will not produce benefits sufficient to justify the potential environmental impacts and litigation that will result if there is inadequate time for proper review. The MMS air quality studies in the Santa Barbara Channel are not directly applicable to nearshore San Diego County; MMS should develop an air quality model for areas south of the Channel before these areas are leased.

San Luis Obispo County

The areawide approach and streamlined presale process may not permit adequate consideration of local land use plans, fishing conflicts, and local government participation in the leasing process. The DPP is overly ambitious. The timing should be more standardized. The new planning areas are in keeping with prior county positions, but the western boundary should not be extended. The supplemental sales and acceleration provisions further the acceleration of the leasing pace and limit effective analysis and mitigation planning. The presale process should: focus on promising acreage; be determined through consultation with State and local government; allow 90 days for governor's comments; and provide special determination for subareas (frontier areas, marine sanctuaries, environmentally sensitive areas and areas with high vessel traffic and military use). Delete leasing north of Morro Bay, a 20-mile buffer zone around Morro Bay, and a 12-mile buffer zone from the sea otter range. Special conditions should be added to require best available control technology (BACT) for air emissions, require pipeline transportation where feasible, phase development, and encourage the use of subsea completions.

San Mateo County

The Board opposes adoption of the Draft Proposed Program for the following reasons: areawide leasing and the streamlined prelease process does not permit adequate consideration of local land use priorities, commercial fishing conflicts, and local agency inputs; the draft does not adequately consider fisheries, navigation, sealane, and military use conflicts; leasing impacts on existing local economies are not considered; the Draft does not consider the relative marine productivity and environmental sensitivity of the planning areas; the DPP does not consider the equitable sharing of developmental benefits and environmental risks; and the DPP does not consider the laws, goals, and policies of California.

Santa Barbara County

Santa Barbara County is anticipating a rapid increase in OCS-related development in the next 6 years: 4,000 percent increase in oil processing, 850 percent increase in gas processing, and 1,500 percent increase in marine terminal activity. The County is in the process of changing their local plans to accommodate the impacts from these existing offshore development proposals and is working with industry to establish monitoring programs to accurately assess local impacts. However, several more developments are likely from State and Federal leases in the Santa Barbara Channel and Santa Maria Basin.

In accordance with the pace, magnitude, and density of development of their coast, the County recommends the following six points for the Proposed Program:

1. Delete the Santa Barbara Channel and Santa Maria Basin until:

   a. The County has implemented its impact monitoring program for development from existing State and Federal leases;

   b. The County completes its comprehensive plans and policy revisions;

   c. Additional production can be accommodated within resource constraints and long-range goals; and

   d. Existing and future lessees are required to comply with air quality standards that are equivalent to those for onshore sources.

2. Include local government costs and costs due to induced growth in the social cost analysis.

3. Provide for equitable Federal revenue sharing according to local impacts sustained.

4. Add a provision for decelerated leasing based on a change in economic conditions, geologic data, and the potential for environmental damage, or the potential for adverse impact on the coastal zone.

5. DOI should establish a close, continuous working relationship with local jurisdictions directly affected by development in Federal waters.

6. Conduct a scoping hearing for the EIS in Santa Barbara.

The following points are recommended for leasing off the County:

1. Delete Channel Islands Marine Sanctuary and buffer zone, Santa Barbara Ecological Preserve and buffer zone, and the Vessel Traffic Separation Scheme area;

2. Identify lease sale areas more specifically;

3. Base the location and timing of sales on local offshore and onshore resource constraints; and

4. To ensure that production can be accommodated within local goals and plans, add the following lease stipulation:

Development and Production Plans (DPPs) must evaluate the onshore capacity of oil and gas processing, storage, and transportation facilities that exist, are approved for construction, or are allowed under the current land use plans of the nearest onshore local government jurisdiction. Development and production activity will be allowed to proceed only when it is demonstrated to MMS that sufficient capacity can be provided, consistent with the local land use plans, to handle the oil and gas production in the time schedule proposed in the DPP.

Santa Cruz County

The Board opposes adoption of the Draft Proposed Program for the following reasons: areawide leasing and the streamlined prelease process does not permit adequate consideration of local land use priorities, commercial fishing conflicts, and local agency inputs; the draft does not adequately consider fisheries, navigation, sealane, and military use conflicts; leasing impacts on existing local economies are not considered; the draft does not consider the relative marine productivity and environmental sensitivity of the planning areas, the draft does not consider the equitable sharing of developmental benefits and environmental risks; and the draft does not consider the laws, goals, and policies of California. The Board also supports continuation of the moratoria offshore California until a permanent program has been adopted to protect and enhance California's coastal dependent economies, environmental resources, and State and national scenic and recreational resources.

Santa Cruz County

The Board of Supervisors has urged enactment of California Assembly Joint Resolution (AJR) 42 and asks the Governor to request the Secretary of the Interior to make deletions as specified in AJR 42 from the 5-year program.

Santa Cruz County, Health Services Agency

California should oppose offshore drilling north of the Santa Barbara County line until the year 2000. Support California Assembly Joint Resolution 42.

Sonoma County

The Draft Proposed Program should not be adopted, and the Central and Northern California Planning Areas should be deleted for the following reasons: there is no consideration of energy conservation and alternative energy development as a substitution for OCS development; planning area

boundaries and proposed sales are not defined based on full consideration of adverse environmental and economic impacts; sensitive areas and multiple use areas are not deleted; the program cost/benefit analyses are not documented; local coastal plans and policies have not been considered; the Draft Proposed Program does not address impacts on coastal dependent agriculture, industry, tourism, and recreation and local costs associated with related onshore development; the program does not address Sonoma County's contributions of a fair share to energy supplies through the Geyser's Geothermal stream field; the program fails to provide direct consultation with local governments and the public; the draft does not consider the equitable sharing of developmental benefits and environmental risks; and areawide leasing and the streamlined prelease process does not permit adequate consideration of local land use priorities, commercial fishing conflicts, or local agency inputs.

Ventura County

The new planning areas allow for more precise definition of problems and issues. The triennial leasing schedule should provide adequate time to review lease sales, but the acceleration provision could result in annual sales. The acceleration provision should be precisely defined, and accelerated sales should occur no more than once every two years. The method for determining lease sale size needs to be clarified. The Proposed Program should be consistent with national energy policy. Leasing in the Southern California Planning area should not occur until DOI adopts air quality standards equivalent to EPA regulations for onshore sources. Additional issues that should be resolved prior

b. Cities

Eureka

The City favors leasing and exploration off the North Coast, particularly within the Eel River Basin between Shelter Cove and the Oregon Border.

Fort Bragg

The City opposes adoption of the Draft Proposed Program for the following reasons: areawide leasing and the streamlined prelease process does not permit adequate consideration of local land use priorities, commercial fishing conflicts, and local agency inputs; the draft does not adequately consider fisheries, navigation, sealane, and military use conflicts; leasing impacts on existing local economies are not considered; the DPP does not consider the relative marine productivity and environmental sensitivity of the planning areas; the DPP does not consider the equitable sharing of developmental benefits and environmental risks; and the DPP does not consider the laws, goals, and policies of California.

Huntington Beach

Huntington Beach supports the 5-year program if lease sales proceed at a slow enough rate and are small enough in scope to allow a thorough evaluation of environmental and economic impacts. The oil spill risk increases with additional rigs and associated transportation; such a spill could harm the marine environment. Offshore oil development affects southern California beaches; it jeopardizes the economy if oil is spilled, detracts from the scenic views and increases emission levels. It was noted that oil facilities also provide employment for local workers. Local participation in the planning process is essential to ensure that concerns are addressed.

Laguna Beach

The City opposes adoption of the Draft Proposed Program for the following reasons: areawide leasing and the streamlined prelease process does not permit adequate consideration of local land use priorities, commercial fishing conflicts, and local agency inputs; the DPP does not adequately consider fisheries, navigation, sealane, and military use conflicts; leasing impacts on existing local economies are not considered; the DPP does not consider the relative marine productivity and environmental sensitivity of the planning areas; the DPP does not consider the equitable sharing of developmental benefits and environmental risks; and the DPP does not consider the laws, goals, and policies of California. The Proposed Program should provide for a permanent moratorium between Catalina Island and the south Orange County coastline.

Lompoc

Comments submitted by the City of Lompoc concur with comments submitted by Santa Barbara County (see Santa Barbara County in this section of Appendix B).

Los Angeles

DOI is not responding positively to the current moratorium legislation; all of the moratorium areas are included in the DPP. Los Angeles supports the 3-Year interval for lease sales but notes that the time between Lease Sales 80 and 95 is only 2 1/2 years. The acceleration provision leaves the impression that there will be no change from the current practice of beginning a new sale immediately after one is completed. The balancing required by the OCS Lands Act is impossible if high risk areas in Santa Monica Bay and adjacent to State oil and gas sanctuaries are mixed in with high value areas. Enlarging the Southern California planning area decreases the possibility of detailed analysis, particularly by local government. The Proposed Program should address the growing potential for renewable resources and conservation, particularly in reference to the moratorium areas.

In the case of Santa Monica Bay, the Draft does not address the impact of significant new NOX sources on the only air basin in the country facing EPA sanctions for not meeting the 1982 NO_2 standard. Oil spills in this area would have an enormous impact on the most heavily used coastal area in the country.

The DPP gives little hope of ending conflicts between DOI and local governments. Debates over moratoria are an interim step to eventual adoption of a more rational planning process. DOI should follow California's policy of establishing oil and gas reserves. The Secretary of the Interior should also meet with local officials, as required in the moratorium legislation.

Manhattan Beach

The City of Manhattan Beach opposes any oil and gas exploration in the Santa Monica Bay and environs; the community supports the comments in the Coastal Commission Executive Director's memorandum of April 2, 1985

Morro Bay

The City opposes adoption of the Draft Proposed Program for the following reasons: areawide leasing and the streamlined prelease process does not permit adequate consideration of local land use priorities, commercial fishing conflicts, and local agency inputs; the draft does not adequately consider fisheries, navigation, sealane, and military use conflicts; leasing impacts on existing local economies are not considered; the DPP does not consider the relative marine productivity and environmental sensitivity of the Planning Areas; the DPP does not consider the equitable sharing of developmental benefits and environmental risks; and the DPP does not consider the laws, goals, and policies of California. The City also recommends no leasing north of the Santa Maria River.

Oceanside

Leasing in the nearshore San Diego area should be restricted due to the limited resources in this area and the potential impacts on recreation and air quality.

Oxnard

The benefits of OCS development extend nationwide, but the public sector costs are localized. Federal leases could not be developed without the support that is provided to the industry by local government agencies, but the analysis for Federal agency development proposals does not address service requirements and fiscal impacts on local government. The Proposed Program should be delayed until mitigation is provided to local governments to cope with service and fiscal impacts from existing leases.

Pacifica

The small reserves in the four Northern California basins do not justify the environmental risks of oil spill hazards, pollution from drilling discharges, air pollution, and onshore siting of processing facilities.

Palos Verdes Estates

Their comments state their continuing opposition to leasing and development in or near Santa Monica Bay. They expressed sensitivity to activities

that could affect intertidal marine life along the shore, especially if an oil spill were to occur. Concern was expressed over adequacy of oil spill containment capabilities.

Preservation of the coastline of Santa Monica Bay for economic and recreation reasons exceeds the benefits that may be derived from what may be a limited source of oil and gas. Reasons for previous deletion of Santa Monica Bay from leasing consideration are still valid and will be for the period covered by the new 5-year program.

Requested that California be further divided into a fourth area to consist of Santa Monica Bay alone, so that an estimate of the resources, economic benefits, and social costs of the area can be put in clear perspective. Delete Santa Monica Bay from consideration in the 5-year program.

Pismo Beach

The DPP does not address impacts on regional economies and local economic bases. The size and location of lease sales are not defined as precisely as possible. There is no assurance that local concerns will be addressed in the presale consultation process. The timing of lease sales is overly ambitious. The flexibility provision and supplemental sales provision further accelerate the schedule and reduce the ability to adequately assess and mitigate environmental impacts. The City recommends reducing the number of California sales, expanding the interval between sales, deleting the flexibility provision and supplemental sales, including the Santa Maria Basin in the Central California planning area, and deleting leasing north of the Santa Maria River.

San Clemente

The Draft Proposed Program extends broad powers to the Secretary of Interior to accelerate sale dates if "international conditions" warrant. The language in the DPP appears to limit community input at the early planning stage.

The areawide leasing concept and reorganization of the California coast need to be addressed. The flexibility provision may be inconsistent with powers granted to the Secretary in the OCS Lands Act.

The overall size of planning areas is increased; reconfiguration increases the number of sales that potentially can take place in the next 5-year period. The 5-year program inadequately addresses existing and anticipated coastal uses and economic impacts. San Clemente opposes southern California nearshore exploration and drilling, citing estimated low yield and high risk to local coastal economies and the environment. San Clemente supports legislative moratoria in nearshore areas; opposes adoption of the Draft Proposed Program as it has been presented.

San Diego

San Diego legislative policy opposes efforts to develop oil and gas resources within 100 miles of the coast unless sufficient reserves exist to be of significant importance to the national energy supply. Benefits and risks of

development of nearshore tracts needs to be balanced. Identify and mitigate the adverse environmental effects relating to air quality, seismic, biological, and socioeconomic impacts.

San Diego supports the San Diego Association of Government's position to delete specific areas off San Diego from the 5-year program. Revise the program to require more stringent air quality regulations, tract-specific analyses, and adequate consultation between Federal, State, and local governments.

Specific comments on the Draft Proposed Program are as follows:

1. Delete areas offered, but not bid upon, or areas deleted from previous lease sales off San Diego from the 5-year program.

2. Delete the area currently covered by the Congressional moratorium off San Diego from Sale 95.

3. Consider the importance of the military training and operating areas off Southern California.

4. Delete areas in water depths greater than 400 meters from Southern California leasing consideration until proven technology has been developed for use nearshore.

5. Change air quality administrative regulations so that offshore developments are regulated in the same manner as onshore developments. Address the air quality concerns of California in the 5-year program.

6. Slow the scheduled pace to one sale every 5 years off Southern California to allow for a thorough Federal, State, and local review.

7. Schedule frequent and substantive consultation to include local representation.

8. Return to tract specific analysis instead of using the areawide leasing concept.

San Francisco

Opposed to the Draft Proposed Program because there is no change in the pace or size of lease sales. The new planning areas should allow more concentrated review, but the new planning area configurations will not slow the pace or scope of lease sales. Environmentally sensitive areas should be deleted. The flexibility provisions are vaguely defined and should not be used to compromise careful environmental review of offshore areas.

San Luis Obispo

The size and location of lease sales are not defined as precisely as possible. There is no assurance that local concerns will be addressed in the presale consultation process. The timing of lease sales is overly ambitious. The flexibility provision and supplemental sales further accelerate the schedule and reduce the ability to adequately assess and mitigate environmental impacts. The City of San Luis Obispo recommends reducing the number of California sales; expanding the interval between sales; deleting the flexibility provision and supplemental sales; including the Santa Maria Basin in the Central California planning area; and deleting leasing north of Pismo Beach. The City also supports continuation of the moratorium to protect the coastal-dependent regional economies.

Santa Barbara

The DPP allows further development in the Santa Barbara Channel, an area already constrained by existing and proposed OCS development. There is little change in the pace of sales. The City of Santa Barbara requested that the Santa Barbara Channel and Santa Maria Basin be deleted from the Proposed Program. Delete marine sanctuaries and federal oil and gas preserves. In the absence of long-term management plans with appropriate prohibitions, the moratorium should be retained. Development of new leases should be phased according to the 600,000 barrel per day capacity provided for in local plans. The offshore air regulations should be implemented before adopting the new 5-Year Program.

Santa Cruz

Santa Cruz opposes adoption of the Draft Proposed Program and urges continuation of a moratorium on exploration and development within California coastal areas until a permanent program is adopted to protect and enhance the California coast. Under the DPP the Secretary of the Interior would be granted broad discretionary authority to accelerate lease sales and to conduct them earlier; the DPP would continue to use areawide leasing actions and a prelease process that would not allow adequate consideration of local issues; it fails to adequately consider existing or anticipated uses of the sea and seabed; it does not consider adverse impacts on existing economic bases; it fails to consider relative marine productivity, environmental sensitivity, and equitable sharing concerns; it fails to consider laws, goals, and policies of the State of California, and does not conduct "critical balancing" as required by the OCS Lands Act.

Santa Monica

Numerous subareas in California have received protection by the Congressional moratorium; protection of these subareas has a wide base of support among the general public and elected officials. Santa Monica seeks to protect its beaches and its open bay.

Santa Monica fears the loss of tourism, the adverse effects on infrastructure, and the high costs of providing schools for the new oil-related population influx. Exclude Santa Monica Bay from the leasing program. Comments

note that air quality impacts are critical to Los Angeles County and that Santa Monica supports air quality concerns expressed in the Southern California Association of Government's comments.

Torrance

Overall concerns are that the 5-year program includes environmentally sensitive areas currently under moratorium. The DPP does not show there is a balance between environmental concerns in these areas and energy needs or national interest. The plan does not show that alternative energy sources are being pursued in concert with OCS development. The plan needs to include the benefits from energy conservation as a means to mitigate scarcity.

The major concern is that OCS development is proposed without a comprehensive national energy policy specifiying California's role or the role of alternative energy sources. Other concerns focus on seismic instability and oil spill potential, air quality, and the commercial and sport fishing industry.

Strong support for early conflict resolution and local participation was noted. The City of Torrance requests removal of environmentally sensitive areas and suggests that other areas be leased by priority as measured by their oil and gas potential.

Watsonville

The City of Watsonville unanimously supports the Congressional OCS drilling moratorium.

c. Special Districts

Association of Monterey Bay Area Governments (AMBAG) (Katy Sears -William, President).

Supports a 15 year moratorium on leasing in the Central California planning area. The Board opposes adoption of the DPP for the following reasons: areawide leasing and the streamlined prelease process does not permit adequate consideration of local land use priorities, commercial fishing conflicts, and local agency inputs; the DPP does not adequately consider fisheries, navigation, sealane, and military use conflicts; leasing impacts on existing local economies are not considered; the DPP does not consider the relative marine productivity and environmental sensitivity of the planning areas; the DPP does not consider the equitable sharing of developmental benefits and environmental risks; and the DPP does not consider the laws, goals, and policies of California.

Association of Monterey Bay Area Governments (AMBAG) (Testimony of Phyllis Price, Member of City Council of Salinas, CA and Vice Chairperson, AMBAG).

In addition to the concerns listed in the AMBAG resolution, onshore oil support activities could result in severe impacts on currently strained groundwater aquifers and wastewater treatment facilities. DOI's proposed air

quality regulations are encouraging, but there are many unaddressed points: the Monterey Bay Unified Air Pollution Control District's goal is to attain the State ozone standard; the proposed thresholds for air quality review, application of BACT, and mitigation measures may not be low enough to prevent air quality degradation; and the definition of temporary emission is too lenient and precludes control of drilling, a major source of NOX.

Association of Monterey Bay Area Governments (AMBAG) (Testimony of Joe Cucchiara, Supervisor, Santa Cruz County, CA)

In addition to the concerns listed in the AMBAG resolution, the DPP should analyze potential impacts on the California Sea Otter Reserve, Elkhorn Slough, Ano Nuevo Island State Reserve, Carmel Bay, Point Pinos, and the seven major research and education institutions in the Monterey Bay area. Unique and sensitive coastal areas should be deleted and retained as emergency energy resources. There is no coherent national energy policy or program, particularly given proposed cuts in energy research budgets and the indefinite moratorium on purchases for the strategic petroleum reserve.

San Diego Association of Governments

The military is a major contributor to the San Diego and State economies; military training and operation areas off Southern California should not be dislocated. Offshore development air quality regulations should be the same as for onshore developments. Only one sale should be held in the Southern California planning area to ensure adequate local, State, and Federal review. There should be a frequent and substantive consultation process. Tract specific analysis rather than area-wide leasing provides for better local evaluations of proposed developments and their local impacts. Subarea deletions should include: tracts offered but not bid on in previous lease sales; nearshore areas currently covered by the Congressional moratorium; military training and operation areas identified in the April 18, 1983 letter by the Department of Defense; and areas with water depths greater than 400 meters, until proven production technology has been developed for use in the nearshore area.

Southern California Association of Governments (SCAG)

Since establishing a schedule is a central object of the Program, not knowing the groundrules for modifying the schedule puts States and local governments at a disadvantage in understanding how it will be implemented. It is essential that all interested parties have adequate opportunities to comment on the proposed flexibility provisions. The presale consultation procedures are extremely positive and should be described in more detail. A process which enables local governments to participate in site selection would be optimal. The balancing and social costs analysis and the methodologies used to evaluate these factors have not been made available to local agencies.

Bay Area Air Quality Management District

No lease sales should occur until DOI has finalized the air quality regulations for California. A cumulative analysis of air quality and related impacts should be conducted. Air emissions from OCS sources should be subject to the same air quality requirements as emissions from onshore sources.

Monterey Bay Unified Air Pollution Control District

The overriding general concern of the District is the insignificance determination made with regard to air quality impacts from offshore oil and gas development. The analysis omits several critical points: a) the cost of EPA sanctions for areas not attaining the ozone NAAQS due to under-controlled offshore sources; b) the impact on industry and the public to mitigate the air quality degradation in order to attain and maintain the Federal ozone standards and to achieve the more stringent California standard; and c) data which is more recent, broader in scope, and geographically specific. The DPP should be based on DOI's proposed air quality regulations. At a minimum, no leasing should occur prior to the implementation of these regulations. Offshore oil and gas drilling and extraction sources should be treated no differently from sources directly onshore. Any program less than this would place an inequitable burden on the industry and public of California.

Florida

a. Counties

Volusia County

The schedule proposes too many sales during the 5-year program. The areawide leasing concept continues to ignore previously negotiated deletions from the sale areas. Deletions based on the memorandum of understanding should apply to future offerings. The promising acreage concept should decrease the potential size of the sale area and thereby the number of objections.

b. Cities

Flagler Beach

Flagler Beach is concerned with the potential for a disaster to the local economy and harm to the beach. Offshore leasing should be allowed only if there is no risk of a spill. Existing technology is not risk-free and money compensation for oil spills is not a relevant safeguard. The City of Flager Beach requested that State and Federal representatives adopt a cautious and conservative approach to leasing.

c. Special Districts

South Florida Regional Planning Council

The Council expressed concurrence with the State of Florida's deferral requests.

Tampa Bay Regional Planning Council

The Council expressed agreement with stipulations and restrictions used in the most recent Eastern Gulf of Mexico sale and believes they should be continued in the future. The Council seeks further protection for living marine resources where water depths are shallower than 70 meters and expressed concern

for protecting extensive seagrass beds that occur in the shallow waters south of 26 degrees N. latitude. Initiate an offshore trust to fund unemployment benefits, and relocation and/or economic adjustment allowances to individuals who lose income due to leasing activities.

Oregon

a. Counties

Coos County

Coos County is extremely pleased that the Oregon coast is being considered for offshore oil and gas leasing and are encouraged by proposals that present the potential for economic benefits. Concerns over coastal environmental damage can be overcome by developing objective factual information about the environmental costs and economic benefits of oil and gas development. Conduct studies, examine the tradeoffs, and give Oregon's south coast economies the opportunity to recover economically.

Curry County

The Board of Commissioners favored and supported the inclusion of Oregon in the new 5-year program. Oregon's south coast needs the economic benefits that would result from this activity. Environmental risks can be minimized by drawing on previous experience.

b. Cities

Cannon Beach

Tourism is an important industry; offshore drilling and the possibility of oil spills is not worth the risk. Cannon Beach is opposed to drilling off the Oregon coast.

E. Environmental and Other Interest Groups

Environmental and other interest groups submitted 21 responses directly to the Department of the Interior. Another 25 such responses (10 of which responded both to the State of California and to the Department of the Interior) accompanied the California Governor's comments and 3 such responses accompanied the Oregon Governor's comments.

Except for comments from Natural Resources Defense Council (NRDC), Greenpeace, and American Fisheries Society, which were thought to represent a national perspective, comments generally focused on regional and local concerns. NRDC's comments were submitted on behalf of themselves, Sierra Club, Environmental Policy Institute, Conservation Law Foundation of New England, and Friends of the Earth.

Organizations having a national perspective, especially NRDC and Greenpeace, submitted detailed comments, recommendations, and thoughtful discussion of issues. Regional and local organizations submitted comments

emphasizing a variety of concerns. Four groups--Marin (CA) Conservation League, California Public Interest Research Group, Mendocino County Democratic Central Committee, and League of Women Voters of California - submitted resolutions adopted by the organizations stating their positions opposing the Draft Proposed Program, opposing drilling off California, and demanding strict environmental protection and responsible management of public resources. Among the many concerns expressed in the comments from environmental and other interest groups and in addition to comments on topics requested in the March 22, Federal Register notice, the following were frequently cited: cumulative impacts, air quality regulations, environmental sensitivities, deep water technology, public involvement, pace of leasing, fiscal impacts, other uses of the seabed and coasts, vessel traffic lanes, oil spill risks and response, ocean dumping of drilling by-products, infrastructure burdens, effects on coastal dependent economies (fishing and tourism), oil and gas transportation strategies, and whales and other marine migratory species.

In the remainder of this section, the concerns of the principal commenters are highlighted with a brief synopsis. The first group includes NRDC, Greenpeace, and American Fisheries Society because their comments are national in scope. Others are organized by State.

1. National Organizations

American Fisheries Society - The 5-year plan is lacking in flexibility and innovation to inventory resources; contains few incentives for exploration in frontier areas; shows excessive sensitivity to some frivolous exclusionary requests; and needs a campaign to educate the public to the environmental risks of alternative energy development strategies.

Greenpeace - To develop the entire OCS without a coherent policy is environmentally dangerous. Areawide leasing perpetuates the "give away" of the nation's resources and poses social and environmental problems; focused leasing does nothing to mitigate problems.

The pace and size of lease sales in the DPP places an extensive burden on State and local governments; Greenpeace requested a return to the tract selection process to allow adequate environmental analysis. The low oil spill rate and assertion that technology exists to contain it are open to empirical challenge. The net social value calculations are flawed because of the treatment of quantifiable and unquantifiable values; the net social value analysis needs to be reworked to incorporate reduced reserve estimates and to provide a true assessment of potential costs. The flexibility provision will require specific guidelines limiting its use; guidelines should be prepared and submitted for public comment.

Sensitive environmental areas and productive marine areas should be deleted; they recommended enacting a "marine park" assessment program similar to the wilderness study area program, to evaluate deletion candidates. Delete the following areas from the 5-year program: Georges Bank; areas off the Gulf Coast of Florida; four northern basins off California, plus a buffer zone in Santa Maria Basin for protection of the southern sea otter range; portions of the southern California planning area, such as the Channel Islands Marine Sanctuary;

the Oregon and Washington coast; Bristol Bay; St. George Basin, a buffer of Unimak Pass, Hope Basin, Aleutian Basin, and a continuation of the exclusion of Aleutian Arc, Bowers Basin, and St. Matthew Hall off Alaska. The list of deletions is not exhaustive; suggested a review of individual State requests.

Several alternatives to OCS development include conservation, enhanced oil recovery, stripper wells, and alternative technologies. Greenpeace generally recommended: abandon areawide leasing, reinstitute tract selection and reduce magnitude and pace; establish a system of "marine parks" to protect sensitive and productive areas and establish an evaluation program to analyze areas nominated by States for deletion from OCS development; improve the environmental analysis of proposed lease sale areas; and restrict Arctic and deepwater development until technology for spill containment and cleanup is available. Specific recommendations for the DPP: rework the cost/benefit calculations based on new data published in the OTA report; change the method of calculating damages and rework the sensitivity and productivity calculations to show variation in the indicators by geographical areas; articulate the criteria for invoking the flexibility provision; and retain the current tract size limit and do not reduce the minimum allowable bid.

Natural Resources Defense Council - The Draft Program proposes more lease sales than the current 5-year program; acreage proposed for leasing will exceed the current one billion acre 5-year program. Include and fully discuss revised resource estimates in the 5-year program. A proper economic analysis supports a more controlled rate of leasing; areawide leasing leads to inefficient resource development and prevents receipt of fair market value. NRDC expressed opposition to areawide leasing. The proposed presale process is imprecise and fails to satisfy section 18(a) requirement. Clarify the difference between modified areawide leasing and focusing on promising acreage. They recommended inserting a step near the end of the prelease process to determine and reconfirm which areas have high industry interest. Requested an explanation of the continuing need for a modified areawide approach in light of the huge inventory of leases industry now holds. Questioned whether the bid evaluation process assures the receipt of fair market value.

NRDC expressed opposition to the flexibility provision. Criteria for triggering the flexibility provision are broad; the provision undercuts the program's value as a planning document. The 5-year program should describe the provision for annual sales more precisely.

Delete sensitive areas at the 5-year program stage; analyze the costs of delaying leasing in such areas. Planning areas should be smaller to allow a more accurate assessment of net social value and the cost of delay in leasing; add a justification for planning area boundaries. Boundaries for California planning areas require further explanation.

Equitable sharing does not justify intensive leasing off California or Alaska. Industry interest as a scheduling factor is overemphasized.

Comments provided detailed suggestions and identified specific concerns regarding the marine productivity and environmental sensitivity analysis.

A detailed discussion of the Draft Proposed Program in terms of intertemporal allocation of resources and fair market value was presented. This discussion concluded that the Department of the Interior's leasing policies of the past five years have resulted in inefficient resource allocations and failure to receive fair market value for the resources, and the Draft Proposed Program represents a continuation of such policies.

The NRDC comments recommended that more precise groupings of planning areas based on net social value be established and used to determine the frequency of sales in planning areas; no need for two sales in the North Atlantic planning area. Alternative energy scenarios should not be limited to imported oil. The assumptions concerning tourism losses and the costs to commercial fishing and subsistence activities are not reasonable.

Other schedule options including a slower pace of leasing, deferrals of sales in areas of low net social value and in areas of highly valuable renewable resources should be considered. Explain why natural gas is uneconomic in the Bering Sea. Provide an explanation of current bid evaluation procedures used to assure fair market value.

2. State and Regional Organizations

A. California

California Public Interest Research Group (CalPIRG) - CalPIRG opposes adoption of the Draft Proposed Program for the following reasons: areawide leasing and the streamlined prelease process does not permit adequate consideration of local land use priorities, commercial fishing conflicts, and local agency inputs; the draft does not adequately consider fisheries, navigation, sealane, and military use conflicts; leasing impacts on existing local economies, local agency concerns, and the public interest are not considered; the draft does not consider the relative marine productivity and environmental sensitivity of the planning areas; the draft does not consider the equitable sharing of developmental benefits and environmental risks; and the draft does not consider the laws, goals, and policies of California.

Capitola Chamber of Commerce - Urged consideration of the problems that will result from Central California offshore drilling; stated that tourism is the local economic base.

Citizens Planning Association of Santa Barbara County, Inc. - Four issues should be addressed in the new program:

1. Delay, for at least three years, further leasing offshore of Santa Barbara County, until comprehensive planning and cumulative impact assessments are done.

2. Future leases in the Santa Barbara Channel/Santa Maria Basin region should contain a stipulation tying MMS approval of Development and Production Plans to the adequacy of the onshore oil and gas infrastructure capacity. The recommended stipulation is contained in the Santa Barbara comments summarized in Part III D of this Appendix.

3. The DOI air quality regulations must be upgraded to the satisfaction of the State Air Resources Board and the affected local air pollution control agencies before the new program is implemented.

4. A satisfactory formula for Federal OCS revenue sharing should be implemented before the new program is adopted.

In addition, summary materials outlining the expected pace of development in the Santa Barbara Channel/Santa Maria Basin were provided.

Desomount Club - Supports renewal of the moratorium on oil and gas drilling off the California coast.

Environmental Center of San Luis Obispo County - The DPP seems to give DOI more control at the expense of State and local control, particularly through the flexibility provisions. The creation of three planning areas serve only to divide and dilute public input into the process, and counters the claims of slowing down the leasing process. The DPP does not address the critical balancing studies, relative marine productivity and environmental sensitivity, and the laws, goals, and policies of California. The DPP fails to adequately consider fishing, recreation, navigation, and military use conflicts. The streamlined prelease planning process will not allow adequate consideration of local land use priorities, commercial fishing conflicts, or local agency input on leasing decisions.

Environmental Coalition - The Coalition is opposed to any further leasing from Mexico to the Canadian border; the number of current leases is more than adequate for American oil needs for the next 10 years. The California coast is too beautiful and vital an area to be exploited by large scale oil development. Fishing and tourism are dependent on a clean and oil-free coast.

Friends of the Sea Otter - All waters north of the Santa Maria River and areas covered by the Congressional moratorium should be deleted. The DPP would: significantly increase the danger of oil spills; compound the adverse impacts of ocean dumping of drilling by-products; contribute to the further degradation of air quality; overwhelm the ability of State and local governments to provide onshore infrastructure to support offshore development, and threaten the well-being of local economies dependent on commercial fishing and tourism. Big Sur and the sea otter range are the most sensitive areas, but would be subjected to 3 lease sales. The accelerated pace of leasing and the unrealistically large planning areas make meaningful environmental assessment impossible. The flexibility provision shows contempt for public involvement and does not balance energy needs with the protection of natural resources. Cumulative impacts from existing leasing have not been addressed or resolved. Oil spill cleanup and containment techniques are incapable of functioning effectively in the sea conditions off California. The Puerto Rican tanker incident demonstrated the ineffectiveness of predictive methods and cleanup technology. The DPP fails to incorporate a uniform pipeline transportation requirement. The DPP does not address a provision for phasing development.

Get Oil Out Inc. (GOO) - Reiterated the need for comprehensive planning outlined in an August 1984 letter. Requested no further lease sales in Santa Barbara Channel until present leases are inventoried, development plans are in place, and plans for onshore support facilities have been completed and are in

place. The DPP fails to address the cumulative impacts of leasing. Requested deletion of tracts within Channel Islands Federal Marine Sanctuary, the Santa Barbara Ecological Preserve and Buffer Zone, and off the coast of Santa Barbara.

Greenpeace Pacific Southwest - The 5-Year program must provide for orderly and environmentally sound development, which is impossible under the proposed pace in the DPP. The DPP is so broad and inclusive that State and local governments will be unable to plan effectively for participation in that leasing and permitting process. The social cost analysis is too generalized. The DPP does not incorporate subarea deletions. The proposed slowdown of the pace is only cosmetic, due to the increase in the number of planning areas, the areawide approach, and the flexibility provision. The costs and risks to the environment exceed the potential development benefits off Central and Northern California. Leasing should not take place in the moratorium areas off Southern California; within Federal ecological preserves, sanctuaries, or buffer zones; and within certain areas off Los Angeles and Ventura Counties, sensitive fisheries tracts off Santa Rosa Island, or within six miles of Catalina Island. Leasing in the Santa Barbara Channel should be deferred until the cumulative impacts of existing leasing are evaluated. No leasing should take place north of the Santa Maria River to protect the sea otter range.

League for Coastal Protection - The DPP lacks the required balancing of environmental sensitivities with economic factors due to the large areas of consideration. Impacts to commercial fishing, kelp harvesting, and tourism are not addressed. Cumulative impacts of accelerated leasing should be evaluated. Local input at the planning stages should be required. The lack of refinery capacity in certain areas is not addressed. Impacts related to air quality degradation should be evaluated. The DPP fails to recognize the biological sensitivity of the new planning areas. Deepwater and subsea technology does not exist commercially at this time. The streamlined approach does not safeguard public and local involvement, and the rapid schedule burdens the affected jurisdictions in their ability to plan for and accommodate the required onshore facilities. The DPP should: return to the basin-by-basin analysis; eliminate leasing off Central and Northern California until all studies are complete; delete those areas covered by the moratoria; delay leasing until air quality regulations are implemented; defer new leasing until cumulative analysis and planning are completed; and require approval of development plans based on onshore resource and planning capacities.

League of Women Voters of California - Emphasized the burdens on communities resulting from the present pace and magnitude of leasing. The League demanded strict environmental protection regulations and responsible resource management.

League of Women Voters of San Luis Obispo County - A moratorium on further leasing off California is appropriate to allow time for a complete assessment of cumulative impacts, development of adequate air quality regulations, establishment of baseline data, and development of adequate onshore infrastructure. The triennial schedule is an improvement, but there is still one lease sale every year. The flexibility provisions and supplemental sales further accelerate the pace, and should be deleted. The DPP increases rather than decreases the size of planning areas off San Luis Obispo County. The new designations inappropriately put the County in the Southern California Planning Area, and split Big Sur and the sea otter range into two. The schedule does not incorporate a mechanism for local, State, and Federal

agencies to reach consensus on just what constitutes a significant impact. No mention is made of OCS revenue sharing. The League supports the California Coastal Commission deletion recommendations. The cost-benefit analysis is superficial. Vessel traffic lanes should be deleted from leasing consideration.

League of Women Voters of Santa Barbara County - The increase in OCS activity has outpaced Santa Barbara County's comprehensive planning policies and process. Marine sanctuaries in the Channel must be protected. Little infrastructure exists near the Santa Maria Basin to accommodate offshore development, and most of the shoreline in this area is part of Vandenburg Air Force Base, outside of the County's planning jurisdiction. Leasing and production plan approval must be tied to the adequacy of onshore oil and gas infrastructure capacities. Because of the present inadequacy of this infrastructure, the Santa Barbara Channel and Santa Maria Basin should be deleted from the planned lease sales, the acceleration provision, and from any supplemental sales. There should be two proposed program EIS scoping hearings in Santa Barbara County. A satisfactory formula for Federal OCS revenue sharing should be implemented prior to further leasing.

League of Women Voters of Santa Cruz County - Concerned that the 5-year program is incompatible with environmental goals and conservation of resources. The League supports continuation of the moratorium. The 5-year program does not adequately consider local land use plans and priorities, commercial fishing conflicts, environmental impacts on marine life of the Santa Cruz and San Mateo coast. The need for study of the longterm implications of OCS activity on the marine environment and onshore air quality was expressed. The 5-year program should consider adverse regional economic impacts; remove the area off Ano Nuevo from leasing consideration; delete sensitive habitats, and areas adjacent to State waters which are in sanctuaries; consider air pollution and the economic impacts of industrialization on tourism. The cost-benefit analysis is misleading; does not consider costs to the State and local communities. Local agencies will need more revenue for infrastructure; the 5-year program makes no mention of sharing revenues; the issue should be resolved prior to adoption of the leasing program. Amend the plan to offer fewer sales and reduce planning area size; delete provisions for flexibility and supplemental sales. The 5-year program should include administrative mechanisms for local and State participation. The leasing program does not provide a precise definition of size, timing, and location of sales; economic and environmental balance; no estimated socio-economic impacts; and the plan does not exclude environmentally sensitive areas from leasing.

League of Women Voters of Sonoma County - There is no consideration of conservation measures. The pace of lease sales is excessive and overlapping, and is made worse by the supplemental sales and flexibility provisions. Planning areas should be reduced to a reasonable size. The DPP should address State coastal management and local coastal plans; the DPP is in conflict with the Sonoma County local coastal plan and existing industry base. Further public and public agency participation is needed. Criteria for selection of areas, evaluation of other uses, and impact significance criteria should be developed with public and local agency participation. More data on impacts and cumulative impacts is needed. The coast-benefit material is not documented. The DPP focuses on correcting the imbalances without consideration of impacts on the environment and affected local areas.

League of Women Voters of the Monterey Peninsula - The League expressed support for California's Assembly Joint Resolution (AJR) 42 and oppose all offshore drilling north of Santa Barbara County until the year 2000.

Marin Conservation League - The League expressed opposition to adoption of the Draft Proposed Program for the following reasons: areawide leasing and the streamlined prelease process do not permit adequate consideration of local land use priorities, commercial fishing conflicts, and local agency inputs; the DPP does not adequately consider fisheries, navigation, sealane, and military use conflicts; leasing impacts on existing local economies are not considered; the DPP does not consider the relative marine productivity and environmental sensitivity of the planning areas; the DPP does not consider the equitable sharing of developmental benefits and environmental risks; and the DPP does not consider the laws, goals, and policies of California. They also expressed support for the Congressional moratorium of HR 1440, and asked for OCS revenue sharing to assist local governments in dealing with the impacts of offshore development.

Mendocino County Democratic Central Committee - They expressed opposition to all offshore oil activities in the sensitive areas off California and are concerned with the adverse economic impacts that these activities will have on the economic base of the North Coast. A copy of the EPA hearing minutes on the McClelland Engineering exploratory permit, held in Mendocino County on November 15, 1985, was also submitted to illustrate the extent of opposition to offshore activities in this area.

Pacific Coast Federation of Fishermen's Associations - The planning areas and lease sales are too large, and there is not certainty that conflicts with commercial fisheries will be resolved. The impact assessments are broad and superficial. Phasing of development to reduce conflicts with coastal dependent industries is not considered. Transportation of crude oil by onshore pipelines should be required. The DPP is no different from the Watt plans, and does not address the legitimate concerns of the fishing industry in California. The new planning areas are not being proposed to better the analyses, but are an attempt to isolate specific areas for early leasing. The flexibility provision should be the responsibility of Congress not the Secretary of the Interior.

The Planning and Conservation League - The necessity of increasing the pace of oil and gas development off California is questionable. The flexibility provisions thwart State and local government involvement in the OCS development process and should be the responsibility of Congress. A more selective leasing approach should be used. A careful study of long-term phased planning would help mitigate the risks to California's coastal resources.

Sierra Club, Loma Prieta Chapter - They opposed the DPP based on the reasoning of California's Assembly Joint Resolution 42.

Sierra Club, San Francisco Bay Chapter - The DPP increases the pace of leasing through annual lease sales. The areawide approach and streamlined provisions minimize the local role in the planning process. No subarea deletions of sensitive areas are included, and sensitive areas off Northern

California, Oregon, and Washington are added. The Puerto Rican tanker incident demonstrated the lack of adequate oil spill technology. The DPP will affect fishing, aquaculture, tourism, and marine research.

Sierra Club, San Mateo County Group of the Loma Prieta Chapter - Voted unanimously to oppose the 5-year program for the entire OCS of the United States. The leasing program is shortsighted, unnecessary, and exposes the coastal environment to risk of oil spills.

Sierra Club, Santa Lucia Chapter - Rural areas such as San Luis Obispo County cannot accommodate the rapid development proposed in the DPP; lease sales should be held every 5 years. The scope of the lease sale areas is too broad; leasing should be divided into four or five planning areas. Known environmentally sensitive tracts should not be leased, such as the area from Pismo Beach to Carmel. Frontier sales should not be held. The environmental assessment process should begin at the leasing stage. Offshore air emissions should meet California air quality standards. Wastewater discharges from platforms should meet State and Federal water quality standards, and drilling by-products should be brought onshore for disposal. Oil transportation should be by pipeline. Platform power should be electric. Clean-up capability must be sited away from sensitive coastal area. Crew transport should be by helicopter to minimize impacts on fishing harbors. Platforms should be sited away from sensitive species habitats. No leasing should occur north of Pismo Beach to Monterey. There is a need for a national energy program based on renewable energy sources and conservation.

Sierra Club, Ventana Chapter - Environmental resources will be adversely affected by offshore drilling. Consider the cumulative impacts of helicopters, supply boasts, and onshore facilities; consider the air pollution, visual degradation, and noise. The Sierra Club expressed opposition to all oil drilling and exploration in California north of the Santa Maria River now and in the foreseeable future.

Whale Center - The pace of leasing is too quick to allow adequate assessment of the cumulative impacts. The areawide and streamlined approaches do not permit adequate consideration of local government concerns, fisheries conflicts, and local land use priorities. The DPP does not adequately assess impacts on marine organisms, other ocean industries, local coastal communities, and existing and anticipated uses of the sea or seabed. The DPP fails to conduct the required balancing, consider environmental sensitivity or productivity of the planning areas, or consider the goals and policies of California. The flexibility provision grants too broad discretionary powers. Adverse economic impacts on local regions are not addressed. The DPP does not evaluate the impacts of drilling and platform installation on whale migration. The Whale Center also provided a report assessing the effects of oil on cetaceans.

B. Florida

Earth First; People for the Ethical Treatment of Animals; and Friends of Whales - Opposed to expanding the development of offshore fossil fuel resources; pursuing offshore energy resources is not desirable or necessary. Oil spills are inevitable; expansion of fossil fuel use is unacceptable. Recommended choosing sites for development which have least wildlife value and the highest degree of human use.

The Florida Public Interest Research Group (Florida PIRG), Inc. - Accelerated areawide leasing has not allowed an adequate assessment of impacts; the proposed process of area identification, which would limit the size of areas to be studied, could improve impact assessments. One public hearing per sale is insufficient; suggested holding evening hearings. Recommended sufficient funding and coordination to complete environmental studies. The decision whether to offer or delete tracts should be based on industry interest, environmental impact assessment, and consultation with States and public.

Florida PIRG expressed concern about the creation of a Straits of Florida planning area. Expressed support for identifying tracts to be offered prior to preparing the draft EIS; requested that specific EIS's be prepared for ecologically distinct regions. They suggested the flexibility to decelerate the leasing pace also be considered. Tract size can be enlarged but keep minimum bid per acre the same. Study the areas where scientific data are lacking before leasing them; avoid offering environmentally sensitive areas.

Sierra Club, Volusia-Flagler Group - Opposed to OCS leases in the South Atlantic, citing threat to water supply and marine life, oil spill risks, aesthetic considerations, and the region's dependence on tourism.

C. Massachusetts

Massachusetts Audubon Society - Comments from Massachusetts Audubon Society were also submitted on behalf of the New England Chapter Sierra Club, and expressed support for the comments submitted by NRDC. Economic analysis and potential oil and gas resources do not justify two sales in the North Atlantic. The interval between sales should allow sufficient time to complete an environmental analysis before the next sale; more than 3 years between sales may be necessary. Abandon areawide and focused leasing; remove environmentally sensitive tracts early; identify a small number of tracts to be offered during in the Call for Nominations. Initiate early consultation to identify and eliminate tracts from further consideration; delete tracts from consideration all tracts in water shallower than 400 meters and in submarine canyons.

D. Oregon

Greenpeace - The 5-year program needs to provide for orderly, environmentally sound development; the current pace has strained West Coast agencies' abilities to do planning and analyses. The new 5-year program is too broad to plan effectively for local participation; it provides generalized analysis of effects on coastal areas. Greenpeace expressed opposition to the method of leasing and to the premature leasing off Oregon. Commented that there is no real difference between focused and areawide approach; focused approach contains no provision to reduce sale size or to delete sensitive areas. The current leasing pace places burdens on local governments. Flexibility to increase the leasing pace should be a Congressional authority to allow for openness and any necessary consultation with local and State governments.

Comments stated that the risks and costs of leasing off Oregon exceed the potential benefits. Delete the Washington-Oregon sale from the Proposed Program. The 5-year program should address the need for specific, site-sensitive analysis. The 5-year program uses simplistic analysis and does not recognize the differences among coastal environments. Develop better methods for impact analysis. Expressed strong objections to the DPP, saying that it poses a serious threat to marine and coastal environments, local economies, and public health. Recommended including changes to size, timing, process, area designations, environmental and impact analysis, and other areas of the 5-year program.

Oregon Natural Resources Council - Expressed concern that leasing Oregon's coast would be a shortsighted action, subjecting the area to a boom and bust economy. Opportunities for conservation outweigh the potential energy benefits from Oregon's coast.

Pacific Fisheries Enhancement, Corp. - Comments expressed concern about arbitrary and capricious implementation of the leasing program off Oregon's coast; they recommended that DOI use caution.

E. Texas

Sierra Club, Lone Star Chapter - Rig availability is a major factor contributing to long lead times for OCS development. Expressed the need to curtail energy use and to make use more efficient rather than to hasten domestic consumption. Drilling and production have both daily and cumulative impacts. Discharges from platforms are a major concern; litter from offshore platforms reaches the beaches.

Biennial sales in the Central and Western Gulf of Mexico would be sufficient; supplemental sales could be biennial also. Acceleration of sales is not warranted. Variation in the minimum bid level should be indexed to the economy. Subareas subject to special consideration should include biologically sensitive tracts, marine sanctuaries to include 4-mile protective zones, fishing banks, and multiple use areas such as fairways, ports, and subsea areas with minerals producing potential.

F. Oil and Gas Industry

Comments received from the oil and gas industry generally focused on the specific topics for which information was requested in the March 22, 1985, Federal Register Notice. The content of those comments is summarized in Part IV of this Appendix and is organized by topic.

The analysis of responses in this part provides general information contained in the oil and gas industry's comments, but not summarized in Part IV. This summary is organized into two categories. The first part is a summary of responses from oil and gas exploration and production companies. The second part is a summary of responses received from oil and gas industry associations and other ocean industry and trade associations. A synopsis of each respondent's comments follows.

1. Oil and Gas Exploration and Production Companies.

Allied Union Texas Petroleum - Strongly supports continuation of the 5-year leasing program concept linked to areawide leasing. The areawide format provides a solid and predictable foundation to plan OCS investment and activities and allows orderly development of offshore resources. Under areawide leasing, in 1984, Union Texas Petroleum participated in four OCS sales; they tripled holdings in the Central and Western Gulf of Mexico and acquired their first Alaskan offshore leases. Drilling on those tracts acquired in 1984 has resulted in hydrocarbon discoveries and more drilling is planned. Concern was expressed that sales in the DPP should not be fewer and less frequent; they expressed support for annual sales in the Central and Western Gulf of Mexico. Support for the flexibility provision, especially as a result of technological advances, was noted. Also, they expressed concern about Congressional moratoria, stating opposition to moratoria and requesting a speedy resolution to the revenue sharing dispute. Union Texas Petroleum endorsed the comments submitted by National Ocean Industries Association and American Petroleum Institute and generally endorsed the 5-year leasing program concept.

Amoco Production Company - Continues to endorse the rationale for areawide offerings. The areawide approach optimally serves the national interest in identifying and developing energy resources while maintaining a proper balance with environmental concerns. The Draft Proposed Program does not adequately reflect the rationale behind the areawide offering system.

Commenting on fair market value, Amoco suggested the need for further improvement. They suggested that, "If a block is offered and then rejected, the bid should be accepted the next time the rejected block is offered for sale (assuming a bid is received for at least the minimum bid). This position is easily supported since after the first sale, industry will know of the bid received on the block as well as the Mean Range of Values of MMS."

Amoco expressed opposition to holding triennial sales in most planning areas outside the Central and Western Gulf of Mexico; they supported triennial sales in the three Atlantic planning areas. Confidentiality period should be extended. Recommended an 8-year lease term on blocks in water depths between 200 and 400 meters and that the requirement to drill on those leases within the first 5-years be removed. Blocks in water depths of 400 meters should carry a 10-year lease term. See Part IV of this Appendix for additional comments on specific topics requested in the Federal Register Notice.

ARCO Exploration Company - Expressed agreement with the flexibility provision to help tailor implementation of the schedule to the market. Concerned with the effect that the emphasis on consensus nominations could have on innovation. The Draft Proposed Program is market-driven and capable of responding to market conditions. ARCO endorsed efforts to resolve conflicts and provisions for early consultation with interested parties. Does not support offering only tracts for which consensus is achieved. Encouraged eliminating or lowering the minimum bid and establishing different minimum bids by planning areas. Supported 8-year lease terms for water depths of 400-900 meters; revise minimum bid requirements for deepwater tracts and for frontier areas. Recommended no changes to the proposed sale schedule.

BP Alaska Exploration Inc. - The 5-year program includes too few sales; schedule should be more aggressive. They noted that their comments refer only to Alaska and California. See Part IV of this Appendix for additional comments on specific topics requested in the Federal Register Notice.

Chevron U.S.A. Inc. - Expressed support for the program as proposed (exceptions were noted in their specific responses to Federal Register Notice topics, see Part IV of this Appendix).

Exxon Company, U.S.A. - Exxon provided two letters of comment. The first letter expressed support for the areawide sale concept; sales should take place on as rapid a schedule as necessary for expeditious, efficient, and environmentally prudent exploration. The letter stated that annual lease sales in the Central and Western Gulf of Mexico are appropriate; biennial sales in Eastern Gulf of Mexico and Northern California were suggested. Preferred annual sale in an Southern California; the Arctic schedule was supported.

Exxon's second letter urged that sales be held as scheduled. Expressed a desire for more aggressive exploration program; emphasized the need for more frequent sales in high interest areas, especially off California and in the Bering Sea. Exxon's comments provided detailed suggestions for the calendar timing of sales to increase the efficiency of Bering Sea and Arctic operations. See Part IV of this Appendix for additional comments on specific topics requested in the Federal Register Notice.

Fairfield Industries - Expressed support for annual areawide offerings in the Central and Western Gulf of Mexico and for the 6-month interval between sales. Recommended advancing the implementation of the 6-month interval between sales to allow better evaluation of tracts.

Marathon Oil Company - Supports the Draft Proposed Program. Stated that a reasonable schedule is needed to allow long-range planning to commence; such a schedule should not recognize or provide for a moratorium. Safeguards in the current presale evaluation process protect the coastal zone and other marine resources from adverse impact. See Part IV of this Appendix for additional comments on specific topics requested in the Federal Register Notice.

Mobil Oil Corporation - Mobil continues to support the areawide leasing concept. See Part IV of this Appendix for additional comments on specific topics requested in the Federal Register Notice.

Shell Oil Company - See Part IV of this Appendix for comments on specific topics requested in the Federal Register Notice.

The Standard Oil Company (Sohio) - Supports an orderly and well designed 5-year program as the one proposed; opposes any diminution of accelerated exploration. Expressed concern that acreage not be deferred or eliminated from leasing. See Part IV of this Appendix for additional comments on specific topics as requested in the Federal Register Notice.

Tenneco Oil - Expressed support for the effort to strike a balance between competing concerns in the development of the OCS in the 5-year program. Emphasized the need for lease offerings in Alaska and California where opportunities for potential new resources lie. Emphasized the importance of maintaining on aggressive offshore program; areawide leasing was cited as the most effective means of achieving exploration and development of OCS oil and gas. See Part IV of this Appendix for additional comments on specific topics requested in the Federal Register Notice.

2. Oil and Gas Industry Comments Included with the California Governor's Letter

ARCO Exploration Company - The proposed lease sale schedule, early consultation procedures, and the flexibility provision should be supported. The proposed schedule and process offer the flexibility to respond to market conditions.

Exxon Company, U.S.A. - The 5-year program recognizes the national priority of resource development, environmental protection, and the States' requirement for meaningful participation in the process. The proposed sale frequency off California is too slow; one sale every two years for Central and Northern California planning areas and an annual sale in Southern California is recommended. Continuing sales on an infrequent basis in the Atlantic is an appropriate provision which recognizes the realities of frontier exploration.

Shell California Production, Inc. - Although they have not completed their review, the DPP is a step in the right direction towards assuring a viable and workable OCS leasing program.

Texaco USA - The Proposed Program will promote offshore development while taking into consideration environmental, fishing, industry, and State and local government concerns. The proposed early consultation and focused leasing approach demonstrates that concerns of State and local government and other users of marine resources will be taken into account, and that the Congressional moratorium is unnecessary. Triennial lease sales should ensure that State and local governments and users of marine resources have ample time to evaluate lease sales, and that the sales will be conducted as scheduled and with minimum conflicts. The restructuring of the California planning areas is responsive to local government requests, and will enable local governments and users of marine resources to thoroughly evaluate the impacts of lease sales.

3. Oil and Gas Industry Associations and other Ocean Industry and Trade Associations.

Alaska Oil and Gas Association (AOGA) - Members of AOGA strongly opposed any general leasing slowdown in the Alaskan OCS. Recommended scheduling frequent sales in high interest areas. Emphasized the need for a firm, dependable schedule. Expressed support for supplemental sales; suggested acceleration of sales would be useful in triennial sale areas, and stated that such an action would be a satisfactory substitute for frequent sales in high interest areas. Urged retention of the areawide concept and stated that areas should not be excluded merely because their hydrocarbon potential is thought to be low.

American Petroleum Institute (API) - Expressed the position that the current 5-year program has served the Nation well. Strongly urged continuation of the areawide leasing concept as a preferable replacement for the tract selection process. Areawide leasing fosters innovative approaches to exploration and allows a more efficient means to gather and use exploration information. The Draft Proposed Program departs from the spirit of areawide leasing and may not meet the basic objectives of the OCS Lands Act Amendments. Under the DPP sale frequency would decrease and the likelihood that promising acreage would be deleted from future sales would increase. API recommended a vigorous areawide offering system and a balanced predictable schedule. See Part IV of this Appendix for additional comments on specific topics requested in the Federal Register Notice.

Chamber of Commerce of the United States - Exploration must be allowed to proceed in order to inventory the resources. Expressed concern about slowing the pace of lease sales from biennial to triennial schedule. Stated members' concern with the emphasis on promising acreage and how it would be implemented. If the emphasis on promising acreage alters the areawide leasing approach, they would oppose the promising acreage concept.

National Ocean Industries Association (NOIA) - Stated that more frequent lease sales would achieve a better balance among the many requirements of the OCS Lands Act Amendments. Restated their position in support of an areawide leasing program citing its numerous benefits. Expressed strong opposition to slowing the pace of leasing; suggested biennial sales in high interest, high value areas outside the Central and Western Gulf of Mexico, and triennial sales in low interest, low value areas. NOIA supports accelerating sales on the basis of significant new information; if scheduled sales are accelerated, they stated that new sales should be added near the end of the 5-year program period. They expressed concern that a slower pace of leasing will adversely affect offshore industries and employment. General support for the proposed locations of sales and for the designation of three California planning areas was expressed. Supported annual supplemental sales as an option. NOIA supports overall program flexibility, but states that the acceleration provision would be unnecessary if biennial sales were continued. Urged flexibility but certainty in the schedule. See Part IV of this Appendix for additional comments on specific topics requested in the Federal Register Notice.

Western Oil and Gas Association (WOGA) - Expressed general support for the Draft Proposed Program. See Part IV of this Appendix for additional comments on specific topics requested in Federal Register Notice.

G. The General Public

Comments from the general public were the most numerous. In addition to the 208 responses received directly by the Department of the Interior, 993 letters of comment were submitted with the California Governor's letter for a total of 1201 responses. Moreover, one submittal consisted of photocopies of 408 individual business cards each with written comments collected in Mendocino County, CA.

Nearly all of the comments from individuals in the general public expressed variations on the same theme -- general opposition to offshore leasing. Some comments focused their opposition to leasing in particular areas such as north of Santa Barbara, in Monterey Bay, off Central California, off Northern California, and off Washington and Oregon, off Santa Cruz County, off Mendocino County, and off Humboldt County. The less focused comments simply stated the individual's opposition to offshore leasing or drilling. Many letters expressed support for continuation of the moratorium north of Santa Barbara to the year 2000.

A few individuals commented in support of offshore leasing and expressed support for the Draft Proposed Program.

H. Congress

Four responses were received from members of Congress. Representative Gene Snyder, 4th District, Kentucky acknowledged receipt of the Draft Proposed Program and expressed appreciation for being kept informed. Representative W. Henson Moore, 6th District, Louisiana and member of the House Budget Committee provided information on the proposed legislation that would settle the OCS 8(g) controversy. His letter urged the Secretary to accept the legislation.

The other two responses were from members of the California Congressional delegation. The response submitted by Representatives Mel Levine, Bill Lowry, and Leon E. Panetta requested a meeting with the Secretary to discuss the long term status of OCS areas off California that have been under moratorium for four years. Their letter expressed support for the Secretary's commitment to conflict resolution through close consultation with Members of Congress and affected States.

They noted that the Draft Proposed Program continues what they called the "objectionable areawide leasing approach" and indicated that the flexibility and supplemental sale provisions may conflict with the commitment to a slower leasing pace, orderly consultations, and early conflict resolution. The inclusion of five sales off California in the Draft Proposed Program was noted to be the same as in the current 5-year program.

Other concerns included the call for negotiations for a long term agreement for dealing with sensitive areas as an alternative to continuing moratoria; they expressed a willingness to enter into such discussions soon and to seek to ensure the cooperation of State and local officials in the matter.

The second letter was from 20 members of the California Congressional delegation. They invited the Secretary to California to view the coastline and to see which areas should be removed from leasing consideration and which areas have little or no opposition. They pledged to work for the success of such a trip.

IV. SUMMARY OF COMMENTS ADDRESSING FEDERAL REGISTER TOPICS

A. The Proposed Configuration of Planning Area Boundaries

1. Federal Agencies (3)

- The State Department commented on the international aspects of planning area configuration, suggesting revision of the boundaries delineated for the North Atlantic, South Atlantic, Straits of Florida, Western Gulf of Mexico, Washington-Oregon, and Chukchi Sea planning areas.

- The Environmental Protection Agency addressed the proposed reconfiguration of California OCS planning areas. They called for more detailed discussion of the proposal to include the Santa Maria Basin in the Southern California planning area, citing oceanographic conditions within that basin which differ drastically from those in the rest of the proposed planning area.

- The National Oceanic and Atmospheric Administration (NOAA) expressed concern that several Alaska OCS planning areas include vast amounts of continental slope and deep-ocean basin that may be beyond foreseeable technology and economics. They called for the environmental studies program to examine the deepwater areas closely before actually deciding to lease them. Also, the proposed reconfiguration of California OCS planning areas was endorsed.

2. State Governors (14)

- Alabama expressed concern with regard to including all of Navy Warning Area W-155 in the Eastern Gulf of Mexico planning area and adjusting the Central Gulf of Mexico accordingly. Questions were raised concerning the effects this would have on future development of blocks which have already been leased in the Mobile Area.

- California included a summary of comments which the governor received from State agencies, local governments, oil industry, organizations, and individuals. These comments are summarized in this appendix under their respective headings.

- Delaware reiterated a suggestion to reconfigure the boundary between the Mid-Atlantic and North Atlantic planning areas.

- Florida stated they are disturbed that the Eastern Gulf of Mexico planning area has been expanded to include both the sensitive area south of 25° N latitude to 24° N latitude and the area east of 82° W longitude. Florida also expressed concern about making the Straits of Florida a distinct planning area.

- Maine stated that it would seem appropriate to remove the Gulf of Maine from the North Atlantic planning area, since it has never been considered for leasing due to unsuitable geology.

- New Hampshire suggested that the impacts of the International Court of Justice's decision on the United States - Canada maritime boundary be discussed.

- New York supported the continued separation of the North Atlantic and Mid-Atlantic, but reiterated their desire to be able to review proprietary data from both planning areas.

- North Carolina found the planning areas to be appropriate, but expressed a concern for more study of the Straits of Florida planning area.

- Oregon stated that the western boundary (128°) of the Washington-Oregon planning area is beyond areas of resource potential.

- Rhode Island noted that the boundary between the North Atlantic and Mid-Atlantic planning areas has not been modified to allow Rhode Island access to proprietary data from North Atlantic leases in accordance with 30 CFR 252.

- Washington considered the western boundary of the Washington - Oregon planning area to be beyond areas of resource potential and technological capability.

- Maryland, New Jersey and Virginia stated their agreement with the proposed configuration of planning areas.

3. State Agencies (5)

The following comments were submitted directly to the Department of the Interior:

- The Senate Rules Committee of the California Legislature submitted a letter signed by David Roberti, Chairman; Gary Hart, Milton Marks, Henry Mello, Hershchel Rosenthal, Diane Watson, Alfred Alquist, Bill Lockyer, Dan McCorquodale, Robert Presly and Walter Steirn. Their comments objected to the reconfiguration of California OCS planning areas, contending that addition of the Santa Maria Basin to the Southern California planning area results in a planning area too large to manage. Three specific recommendations were made:

  (1) retain the current Southern California configuration;

  (2) designate the Santa Maria Basin from Point Conception to the Santa Maria River as the new Central California planning area; and

(3) include the area north of the Santa Maria River in a new Northern California planning area.

- The California Department of Justice stated that the three proposed California planning areas are far too large and cited a previous comment which suggested dividing the California OCS into eight planning areas.

- The California Coastal Commission objected to the establishment of three planning areas with the Santa Maria Basin placed in the Southern California planning area. They cited ecological criteria and planning burdens as the basis for objection.

The following comments were forwarded by the Governor of California's letter:

- The Department of Fish and Game stated that placement of the Santa Maria Basin in the Southern California planning area will make evaluation of leasing activities in that area more difficult since it is within a biological transition zone. They recommended that the Santa Maria Basin be included in the Central California planning area or established as a separate planning area.

- The California State Lands Commission noted great biological and oceanographic differences within the proposed Southern California planning area due to moving its boundary northward.

The following comment was forwarded by the Governor of Oregon's letter:

- The Department of Geology and Minerals Industries commented that the area between 126 and 128 W longitude is in water too deep for present production technology.

4. Local Governments (17):

The following comments were submitted directly to the Department of the Interior:

- Several local governments commented on this topic by noting the reconfiguration of California OCS planning areas in resolutions stating general opposition to the Draft Proposed Program. These include: Association of Monterey Bay Area Governments, County of Santa Cruz, County of Mendocino, City of Laguna Beach, County of San Mateo, County of Monterey, County of Sonoma, City of Morro Bay, County of San Luis Obispo, and City of Santa Cruz.

- The City of Pismo Beach submitted a resolution recommending reconfiguration of the California OCS by placing the Santa Maria Basin in a Central California planning area extending from Point Arguello to San Francisco Bay.

- The County of San Luis Obispo submitted a resolution expressing support for the proposed reconfiguration of California OCS planning areas with the exception of expansion of seaward boundary limits.

- The City of Los Angeles stated that enlarging the Southern California planning area will decrease the possibility of performing detailed environmental analysis of the area.

- The County of Santa Cruz submitted technical comments stating that smaller planning areas will enable more comprehensive and accurate environmental assessment of the Central California Basin.

- The City of Monterey's comments included a statement by a member of the Board of Supervisors that the California OCS planning areas will still be too large.

- The City of San Clemente alleged that reconfiguration of California OCS planning areas increases the overall size of the area under consideration for lease.

- The County of Ventura concurred with the reconfiguration of planning areas, but anticipated that subdivision of the former Northern and Central California planning area would result in fragmented comments on OCS leasing issues from a region lacking experience with OCS activity.

The following comments were forwarded by the Governor of California's letter:

- The City of San Francisco stated that the reconfigured California OCS planning areas should allow more concentrated review of leasing issues, but the new designations will not slow the pace or scope of lease sales.

- The City of Watsonville noted the reconfiguration of California OCS planning areas in a resolution stating general opposition to the Draft Proposed Program.

5. Industry (13)

- Chevron, Amoco, BP Alaska, Marathon, Shell, Texaco, Western Oil and Gas Association, American Petroleum Institute, and National Ocean Industries Association (NOIA) concurred with the proposed configuration of planning areas and specifically endorsed the reconfiguration of California OCS planning areas. Chevron proposed redrawing the outer boundaries of planning areas along the 3000 meter isobath. BP Alaska and NOIA specifically endorsed the proposed configuration of the Beaufort Sea planning area. Marathon endorsed establishment of the Straits of Florida planning area, and Texaco endorsed the South Atlantic planning area. NOIA endorsed extension of the outer boundary of the Northern California and Washington-Oregon planning areas.

- Exxon supported the proposed configuration of all planning areas except the Straits of Florida, the separation of which they believe is of no practical value. The American Petroleum Institute shared this opinion of the Straits of Florida planning area.

- Mobil proposed moving the deepwater boundary between the Central and Western Gulf of Mexico planning areas west to represent an extension of the current Texas/Louisiana offshore shelf boundary.

6. Environmental and Other Organizations (9)

The following comments were submitted directly to the Department of the Interior:

- The Marin Conservation League and the California Public Interest Research Group noted the reconfiguration of California OCS planning areas in a resolution stating general opposition to the Draft Proposed Program.

- The Environmental Center of San Luis Obispo County commented that the proposed reconfiguration of California OCS planning areas serves only to divide and dilute public input to the leasing process.

- The League of Women Voters of San Luis Obispo County commented that the reconfiguration of California OCS planning areas has not resulted in smaller areas for San Luis Obispo County. They also commented that planning area boundaries have been extended beyond areas of technological capability.

- Get Oil Out, Inc., stated that the reconfiguration of California OCS planning areas effects a more equitable leasing program.

- The Florida Public Interest Research Group stated they have no objection to the proposed configuration of planning areas, but are concerned by the creation of the Straits of Florida area.

- The Natural Resources Defense Council suggested that planning areas be more narrowly defined to promote more accurate assessment of net social value and the cost of delay in leasing. They also requested a justification of the proposed configuration and questioned the reconfiguration of California OCS planning areas.

The following comments were forwarded by the Governor of California's letter:

- The Pacific Coast Federation of Fishermen's Associations commented that the proposed planning areas are too large and form the basis of an attempt to isolate specific areas for early leasing.

- The Santa Lucia Sierra Club Chapter stated that California should be divided into four or five planning areas.

7. Private Citizens (1)

Mrs. Jeanne Morris of Palo Alto, California stated that she strongly objects to the reconfiguration of the California OCS planning areas.

8. Congress (1)

A letter signed by Congressmen Mel Levine, Bill Lowry, and Leon K. Panetta stated that they hope the reconfiguration of California OCS planning areas will facilitate more adequate environmental and economic impact assessments.

B. <u>The appropriateness of the number of proposed sales and the interval between proposed sales.</u>

1. Federal Agencies (2)

- The Environmental Protection Agency recommended that the range of alternative leasing schedules proposed be widened to provide longer intervals between sales in certain areas where triennial sales are now proposed.

- NOAA stated support for triennial leasing in Alaska OCS planning areas and suggested that the 3-year interval between sales be increased in certain situations.

2. State Governors (20)

- Alabama concurred with the number and timing of sales proposed in the Central and Western Gulf of Mexico OCS planning areas, but found the proposed pace of leasing in other areas insufficient to contribute significant discoveries of oil and gas.

  They also requested acceleration of the schedule for the Eastern Gulf of Mexico planning area should major discoveries be found in that area.

- California included a summary of comments which the Governor received from State agencies, local governments, oil industry, organizations and individuals. These comments are summarized in this appendix under their respective headings.

- Louisiana stated that holding annual sales in the Central and Western Gulf of Mexico planning areas and triennial sales in other areas will result in increasing the rate of depletion of the resources in the former areas and prolonging the life of those in the latter areas. They also commented that continuing annual areawide sales in the Gulf extends a noncompetitive atmosphere resulting in less-than-optimum leasing revenues.

- Maine commented that the proposed triennial pace in the Atlantic is appropriate, but requested more explanation of the schedule before actually endorsing the timing of sales in the North Atlantic planning area.

- Massachusetts stated that only one North Atlantic sale is warranted during the 1986 - 1991 period.

- New Jersey recommended deceleration of the sale schedule for both the Mid-Atlantic and North Atlantic planning areas.

- Oregon noted that the time proposed for conducting environmental studies prior to a sale in the Washington-Oregon planning area is inadequate.

- Texas commented that the proposed schedule very nearly approximates the current rate of lease sales being held.

- Alaska, Connecticut, Delaware, Florida, Georgia, Maryland, New Hampshire, North Carolina, Rhode Island, South Carolina, Virginia, and Washington agreed with the proposed number of sales and interval between them.

3. State Agencies (6)

The following comments were submitted directly to the Department of the Interior:

- Jack O'Connell, Assemblyman of the 35th district of the California legislature, stated that the proposed pace of leasing off California is rapid and will create significantly greater burdens for more onshore facilities to handle production.

- The Senate Rules Committee of the California Legislature commented that the reconfiguration of California OCS planning areas and the scheduling of supplemental sales serves to accelerate, rather than slow, leasing in those areas.

- The California Department of Justice stated that addition of supplemental sales has increased the pace of leasing, and the proposed schedule must be modified to slow the pacing of sales if it is to meet the standards of the OCS Lands Act.

- The California Coastal Commission stated that concerns they have raised previously, including the pace of leasing, have not been addressed.

The following comment was forwarded by the Governor of California's letter:

- Dan Hauser, Assemblyman of the California Legislature, stated that the proposed schedule accelerates leasing in the Northern California planning area.

The following comment was forwarded by the Governor of Oregon's letter:

- The Department of Geology and Mineral Industries stated that the number and timing of sales scheduled for the Washington-Oregon planning area should be reevaluated, and a staged program of sales should be considered as an alternative.

4. Local Governments (24)

The following comments were submitted directly to the Department of the Interior:

- Several local governments commented on this topic by noting the number and timing of lease sales proposed off California in resolutions stating general opposition to the Draft Proposed Program. These include: Association of Monterey Bay Area Governments; County of Santa Cruz: County of Mendocino; City of Laguna Beach; County of San Mateo; County of Monterey; County of Sonoma; City of Morro Bay; and City of Santa Cruz.

- The City of Los Angeles supported the triennial pacing proposed for the Southern California Planning Area, but noted that the interval between Sale 80 and proposed Sale 95 is actually 2½ years, not 3 years.

- The City of Pismo Beach stated in a resolution that the timing of proposed sales is overly ambitious and recommended that the number of sales be reduced and the interval between them expanded.

- The County of San Luis Obispo recommended in a resolution that the timing between proposed sales be standardized, providing a minimum of 12 months between sales off California and 3 years for sales in frontier areas.

- The County of Santa Cruz submitted technical comments stating that basing the pace of leasing on the number of sales per planning area results in the scheduling of more sales in the Central and Northern California planning areas.

- The City of Santa Barbara stated that annual leasing activity in the Southern California planning area is highly probable under the proposed schedule. They recommended that leasing and development be phased, taking into account support facilities, infrastructure and resource constraints.

- The San Diego Association of Governments commented that 2 sales off Southern California in a 5-year period is unrealistic for adequate local, State, and Federal review. They and the City of San Diego called for no more than one sale every 5 years.

- The City of San Clemente stated that the reconfiguration of the California OCS potentially increases the number of sales which can take place during the 5-year schedule.

- The County of Ventura commented that the triennial leasing schedule is welcome.

- The County of Santa Barbara stated that the timing of sales should be based on the ability of specific areas to absorb impacts, rather than on a fixed number of years between sales.

- The City of Santa Monica stated they are encouraged that the proposed schedule slows the pace of lease sales.

The following comments were forwarded by the Governor of California's letter:

- The City of Lompoc recommended addition of a deceleration provision based on economic conditions, geologic data, and potential for adverse impacts on the environment and the coastal zone.

- The City of San Francisco commented that the proposed schedule does not slow the pace of leasing.

- The City of Watsonville submitted a resolution echoing the one submitted by the County of San Luis Obispo.

The following comment was forwarded by the Office of the Governor of Florida:

- The County of Volusia stated that the schedule proposes too many sales during the 5-year program.

5. Industry (17)

- ARCO and Texaco concurred with the proposed leasing schedule.

- The U.S. Chamber of Commerce and the Alaska Oil and Gas Association stated their general opposition to deceleration of the pace of leasing.

- Sohio and Tenneco stated their agreement with annual leasing in the Central and Western Gulf of Mexico planning areas and their opposition to slowing the pace elsewhere, particularly in the Eastern Gulf of Mexico planning area. They also raised the concern that the triennial leasing pace is not compatible with regulations requiring public release of well information 2 years after its date of submission.

- Union Texas Petroleum, Chevron, BP Alaska, Shell, National Ocean Industries Association, Exxon, Amoco, Western Oil and Gas Association, and American Petroleum Institute generally agreed with the annual pace of leasing in the Gulf of Mexico and stated their preference for biennial leasing in most other planning areas. Several of these companies made specific recommendations for scheduling in particular planning areas, and Exxon presented a complete alternative 5-year schedule.

- Fairfield Industries concurred with the annual pace of leasing in the Central and Western Gulf of Mexico planning areas, but suggested having 6 months' separation between central and western sales, commencing in 1986 rather than 1987.

- Marathon endorsed annual leasing in the Central and Western Gulf of Mexico planning area and stated support for triennial leasing elsewhere as long as acceleration will be possible under certain conditions.

6. Environmental and Other Groups (17)

- The San Francisco Bay Sierra Club Chapter, League of Women Voters of San Luis Obispo County, Environmental Center of San Luis Obispo County, and Whale Center commented that the proposed scheduling would not slow the pace of leasing off California as a whole, since there would be one sale off California per year.

- The Marin Conservation League and the California Public Interest Research Group both submitted resolutions noting the proposed pace of leasing and expressing general opposition to the Draft Proposed Program.

- Friends of the Sea Otter commented that leasing would be accelerated under the proposed schedule.

- Get Oil Out, Inc. stated that triennial leasing is a step in the right direction.

- Greenpeace cited triennial leasing as a general improvement, but stated that it does not change the situation of California as a whole. They also commented that annual leasing in the Central and Western Gulf of Mexico planning areas forces those areas to assume a disproportionate amount of environmental and economic costs of development.

- The Natural Resources Defense Council commented that the proposed schedule does not slow the pace of leasing and offers more sales than the current 5-year program.

- The Sierra Club Lone Star Chapter (Galveston, Texas) commented that biennial sales in all of the Gulf of Mexico would be sufficient.

- The Massachusetts Audubon Society stated that the interval between sales always should be long enough to complete gathering and analysis of environmental information, noting that in some cases the process could exceed 3 years.

- The Florida Public Interest Research Group stated their agreement with triennial leasing off Florida.

The following comments were forwarded by the Governor of California's letter:

- Greenpeace Pacific Southwest stated that the slowdown of the pace of leasing is only cosmetic.

- The League of Women Voters of Sonoma County commented that the pace of lease sales is excessive and overlapping.

- The Santa Lucia Sierra Club chapter stated that lease sales should be held every 5 years.

- The League of Women Voters of Santa Cruz County called for phased lease sales in a national sequence.

7. Private Citizens (0)

No specific comments on this topic were received.

8. Congress (1)

A letter signed by Congressmen Mel Levine, Bill Lowry, and Leon R. Panetta noted that 5 sales are scheduled off California, placing a significant planning burden on the State.

C. <u>The appropriateness of the location of proposed sales</u>

1. Federal Agencies (1)

- NOAA stated support for the decision not to include the St. Matthew -Hall, Aleutian Basin, Aleutian Arc, and Bowers Basin planning areas in the schedule.

2. State Governors (13)

- Alabama commented that more sales should be held outside the Gulf of Mexico to conduct a timely inventory of OCS oil and gas reserves.

- Alaska stated agreement with the decision not to schedule sales in the St. Matthew-Hall, Aleutian Arc, Aleutian Basin and Bowers Basin planning areas due to low geologic potential.

- California included a summary of comments which the governor received from State agencies, local governments, oil industry, organizations, and individuals. These comments are summarized in this appendix under their respective headings.

- Massachusetts commented that the North Atlantic planning area is too environmentally sensitive and contains too little promising acreage to justify leasing.

- Oregon gave qualified approval for including the Washington-Oregon planning area in the leasing schedule.

- Louisiana and Texas commented that the proposed locations are inappropriate because they do not provide for equitable sharing of leasing among various regions.

- Maryland, New Hampshire, New Jersey, South Carolina, and Virginia stated their general agreement with the proposed locations.

3. State Agencies (6)

The following comments were submitted directly to the Department of the Interior:

- Jack O'Connell, Assemblyman, 35th District of the California Legislature, commented that he opposes leasing off California.

- The Senate Rules Committee of the California Legislature redefined the Northern California planning area as the area north of the Santa Maria River and expressed opposition to leasing in this area.

- The California Department of Justice expressed opposition to leasing in the Central and Northern California planning areas.

- The California State Senate Majority Leader expressed opposition to including the Northern California planning area in the proposed leasing schedule.

The following comments were forwarded by the Governor of California's letter:

- Assemblyman Sam Farr stated opposition to leasing in the Central and Northern California planning areas.

- Assemblyman Dan Hauser stated opposition to leasing in the Northern California planning area.

4. Local Governments (15)

- Several local governments noted the location of sales off California in resolutions stating general opposition to the Draft Proposed Program. These include: Association of Monterey Bay Area Governments, County of Santa Cruz, County of Mendocino, City of Laguna Beach, County of San Mateo, County of Monterey, County of Sonoma, City of Pismo Beach, City of Morro Bay, County of San Luis Obispo, and City of Santa Cruz.

- Both the City and County of Santa Barbara stated the belief that the proposed leasing schedule does not locate sales in a manner providing for equitable sharing of developmental benefits and environmental risks among various regions of the nation.

- The Association of Monterey Bay Area Governments and the Monterey Bay Unified Air Pollution Control District expressed opposition to leasing in the Central California planning area.

- The City of Eureka endorsed proposed leasing in the Northern California planning area.

5. Industry (10)

The following comments were submitted directly to the Department of the Interior:

- Chevron, Shell, Marathon, National Ocean Industries Association, Sohio, and Amoco stated general agreement with the location of proposed sales.

- Tenneco commented that renewed emphasis should be placed on offering leases in Alaska and California OCS regions, where the greatest potential for new resources exists.

- Exxon stated that only tentative sales should be planned for low interest areas.

- Western Oil and Gas Association commented that due to unique and innovative exploration philosophies, high interest in an area on the part of a majority of industry members should not be an absolute prerequisite for determining sale location.

- The American Petroleum Institute urged that the location characteristics of the present 5-year program be maintained in the next program.

6. Environmental and Other Groups (7)

The following comments were submitted directly to the Department of the Interior:

- The Marin Conservation League and the California Public Interest Research Group noted the location of sales off California in resolutions stating general opposition to the Draft Proposed Program.

- The League for Coastal Protection commented that no leasing should take place in the Central and Northern California planning areas until studies are completed.

- The Florida Public Interest Research Group stated that they do not object to the proposed location of sales.

- The Natural Resources Defense Council suggested that lower resource estimates indicate that areas low in hydrocarbon potential and high in marine productivity and sensitivity should not be leased.

- Greenpeace commented that leasing should not be conducted in the Washington-Oregon and St. George Basin Planning areas.

The following comment was forwarded by the Governor of California's letter:

- The Environmental Coalition stated opposition to leasing off the entire west coast.

7. Private Citizens (155)

- Several citizens of California submitted comments, the great majority of which opposed the location of lease sales off California.

- A small number of citizens of Washington, Oregon, and Florida submitted comments stating opposition to leasing in planning areas off their State.

8. Congress (0)

- No specific comments on this topic were received.

D. <u>The Proposed Presale Process</u>

1. Federal Agencies (4)

- NASA and NOAA stated agreement with the proposed presale process. NOAA emphasized the importance of defining geologic structures early in the presale process.

- The Department of Defense commented that more prominent display of their use areas would facilitate conflict identification and resolution in the presale process.

- The Department of Justice commented that concentration on promising acreage will limit the number of blocks offered while maintaining a high level of flexibility, thereby serving to ameliorate possible leasing concerns.

2. State Governors (20)

- Alaska stated a preference for returning to the tract selection process or an analogous focused process to facilitate impact analyses.

- California commented that the proposed presale process appears to offer the principles and provisions necessary to address State and local concerns.

- Florida stated that areas of deferral and actual industry interest for a sale should be decided before the draft environmental impact statement prepared for that sale is released.

- Louisiana commented that description of specific prelease mechanisms and procedures is necessary.

- Maine proposed that consideration be given to prelease options which combine the best features of both the areawide and tract selection leasing processes.

- Massachusetts commented that smaller sale areas should be defined to allow States to concentrate better on those areas likely to be leased.

- Oregon reiterated a request for abandoning the areawide leasing concept.

- Rhode Island endorsed focused leasing as a reasonable compromise between the areawide and tract selection approaches, but stated that the presale consultation process must be clarified. They also commented that a Request for Interest step should be considered for unproven areas such as the North Atlantic.

- Texas reported having difficulty discerning the difference between areawide leasing and leasing of promising acreage. An explanation of the differences was requested.

- Washington commented that focused leasing is an improvement over the areawide process, but does not fulfill the need for a process which provides for initial identification and deletion of certain areas.

- Alabama, Connecticut, Delaware, Maryland, New Hampshire, New Jersey, New York, North Carolina, South Carolina, and Virginia stated their general agreement with the proposed prelease process. Maryland also suggested including a Request for Interest step for sales proposed in areas which have experienced recent disappointing drilling results.

3. State Agencies (1)

- The California Department of Justice commented that areawide leasing should be abandoned and tract selection procedures should be reimplemented.

4. Local Governments (16)

- Several local governments submitted resolutions stating general opposition to the Draft Proposed Program. These resolutions stated that the proposed prelease process would not permit adequate consideration of local land use priorities, commercial fishing conflicts, or local agency input to leasing decisions. Resolutions were submitted by the following: Association of Monterey Bay Area Governments, County of Santa Cruz, County of Mendocino, City of Laguna Beach, County of San Mateo, County of Monterey, County of Sonoma, City of Morro Bay, County of San Luis Obispo, and City of Santa Cruz.

- The City of San Clemente expressed opposition to areawide leasing and the proposed prelease process.

- The Southern California Association of Governments (SCAG) and the County of Ventura endorsed the concept of promising acreage as a constructive alternative to areawide leasing. SCAG requested inclusion of more information on the prelease process in the proposed program.

- The City of San Diego and the San Diego Association of Governments both expressed support for the tract selection prelease process.

- The City of Los Angeles commented that the concept of promising acreage will not change appreciably the leasing process for the Southern California planning area.

5. Industry (17)

- BP Alaska and Texaco endorsed the proposed presale process.

- Union Texas Petroleum, National Ocean Industries Association (NOIA), Alaska Oil and Gas Association, Western Oil and Gas Association, Mobil, American Petroleum Institute (API), and U.S. Chamber of Commerce stated their preference for the areawide process.

- Shell, NOIA, API, Sohio, and Exxon cited inequities in the procedures governing submission of positive and negative lease sale nominations, and they requested that the procedures be made similar for both types of nominations.

- Exxon and ARCO expressed concern that the proposed emphasis on consensus could cause unique exploration philosophies held by one or a few companies to be ignored or discounted.

- Chevron generally endorsed the concept of applying the Request for Interest stage in areas of relatively low industry interest, but pointed out timing problems with the Request for Interest for the Shumagin sale proposed for 1990.

- Marathon cautioned against adding unnecessary presale steps and supported the Request for Interest stage only for lease sales in low interest areas.

- Tenneco stated their support for early resolution of potential conflicts, but identified the "drilling window" concept applied to the Eastern Gulf of Mexico planning area as an impediment to exploration and development.

- Exxon commented that the Request for Interest stage might cause delay to the prelease process and added that predictions of interest made so far before a sale might not be dependable. Amoco expressed similar concerns and suggested that the Request for Interest stage be restricted to frontier exploration sales.

- Mobil suggested that the Request for Interest and the Call for Information and Nominations be used to identify special leasing terms and conditions which would provide the necessary incentive for industry to develop oil and gas resources in deeper and more inaccessible areas.

- The American Petroleum Institute commented that the Request for Interest stage is unnecessary and should not be added to the presale process.

6. Environmental and Other Organizations (11)

- The League of Coastal Protection, San Francisco Bay Sierra Club Chapter, Environmental Center for San Luis Obispo County, Massachusetts Audubon Society, Greenpeace, and Natural Resources Defense Council (NRDC) stated their opposition to areawide leasing. The last three organizations stated opposition to focused leasing, and Greenpeace and NRDC commented that the difference between the areawide and focused approaches is imperceptible. The same three organizations also commented that adequate environmental impact statements cannot be written under the areawide or focused process. NRDC posed several questions requesting more specific information concerning the proposed presale process.

- The Marin Conservation League and the California Public Interest Research Group cited the proposed prelease process in resolutions expressing general opposition to the Draft Proposed Program.

- The League of Women Voters of San Luis Obispo commented that there is a need for a process by which actual consensus on leasing issues can be reached by local, State, and Federal agencies.

- Get Oil Out, Inc. endorsed efforts to limit the size of areas proposed for lease.

- The Florida Public Interest Research Group commented that the proposed presale process offers significant improvement over the current process. They also suggested that an environmental impact statement be prepared for each ecologically distinct region included in a sale area.

7. Private Citizens (3)

- The comments from private citizens expressed opposition to areawide leasing.

8. Congress (1)

- A letter signed by Mel Levine, Bill Lowry, and Leon E. Panetta stated they are concerned that areawide leasing would be retained in the next program.

E. <u>The proposed means of pursuing flexibility in the new program in light of uncertainty over future oil and gas prices and national energy needs.</u>

<u>(i) Flexibility (acceleration) provision</u>

1. Federal Agencies (3)

- The Department of Energy endorsed the proposed flexibility provision and urged that the provision be explained fully to avoid misunderstanding and controversy.

- The Environmental Protection Agency commented that the acceleration of lease sales could cause planning disruptions and uncertainty, citing NPDES permitting as a process which would be affected. They suggested that diligence requirements be changed instead of adopting the proposed flexibility provision.

- NOAA commented that the development of specific guidelines to implement the flexibility provision is of great interest to them. They also stated that acceleration of leasing in the Navarin Basin, Beaufort Sea, North Aleutian Basin, and St. George Basin planning areas should be viewed with caution.

2. State Governors (15)

- Alaska and South Carolina expressed a need for more information about the flexibility provision and urged that the provision be explained fully to avoid misunderstanding and controversy.

- California included a summary of comments which the Governor received from State agencies, local governments, oil industry, organizations, and individuals. These comments are summarized in this appendix under their respective headings.

- Florida commented that accelerated leasing in certain areas may conflict with the goals of the new 5-year environmental studies program.

- Massachusetts cited a need for more information and stated that the flexibility provision may be inconsistent with the OCS Lands Act.

- Oregon requested that the flexibility provision be deleted from the program.

- Rhode Island stated that the flexibility provision appears to be a good idea, but more information is needed concerning it.

- Alabama, Maryland, New Jersey, Virginia, New Hampshire, Connecticut, Maine, and Hawaii endorsed the proposed provision. Alabama cited the Eastern Gulf of Mexico planning area as a prime place for application of the provision. New Jersey emphasized that adequate consultation with affected States must be a part of any implementation of flexibility.

3. State Agencies (5)

The following comments were submitted directly to the Department of the Interior:

- The California Coastal Commission and the California Department of Justice commented that the proposed flexibility provision appears to violate section 18(e) of the OCS Lands Act. The latter agency also stated that it is unclear how the provision would be implemented.

- The Senate Rules Committee of the California Legislature expressed strong opposition to the proposed flexibility provision.

The following comments were forwarded by the Governor of California's letter:

- Assemblyman Dan Hauser commented that the proposed flexibility provision would accelerate leasing in the Northern California planning area.

- The State Lands Commission commented that accelerating sales could strain State review of environmental impact statements.

4. Local Governments (17)

The following comments were submitted directly to the Department of the Interior:

- Several local governments noted the proposed flexibility provision in resolutions stating general opposition to the Draft Proposed Program. These include: Association of Monterey Bay Area Governments, County of Santa Cruz, County of Mendocino, City of Laguna Beach, County of San Mateo, County of Monterey, County of Sonoma, City of Pismo Beach, City of Morro Bay, County of San Luis Obispo, and City of Santa Cruz.

- The City of Santa Barbara and the County of Ventura commented that the proposed flexibility provision will help bring about annual leasing. Ventura recommended that sales be scheduled no more than once every 2 years.

- The Southern California Association of Governments commented that the proposed flexibility provision must be described more clearly and be subjected to public review and comment.

- The County of Santa Cruz commented that the flexibility provision is probably the most important aspect of the proposed leasing program for the people of Santa Cruz. They also stated that the provision appears to be a major step back for local governments attempting to ensure that location and timing of lease sales is consistent with protection of coastal resources.

- The City of San Clemente commented that the proposed flexibility provision appears to be inconsistent with the OCS Lands Act.

- The County of Santa Barbara stated that if a flexibility provision is included in the leasing program, it must be offset by a deceleration provision also included in the program.

The following comment was forwarded by the Governor of California's letter:

- The City of Los Angeles commented that the proposed flexibility provision would result in the practice of beginning a new lease sale immediately after one is completed.

- The City of Lompoc suggested adding a deceleration provision.

5. Industry (15)

- Chevron, Marathon, Shell, National Ocean Industries Association (NOIA), Sohio, Union Texas Petroleum, Texaco, Western Oil and Gas Association (WOGA), and Mobil generally endorsed the proposed flexibility provision.

- BP Alaska, NOIA, Tenneco, Sohio, Union Texas Petroleum, Exxon, WOGA, and U.S. Chamber of Commerce addressed this topic by stressing the need for overall reliability in the program.

- Exxon endorsed the concept of accelerating sales, but stated a wish to have sales added to the schedule or have biennial leasing at the outset.

- Alaska Oil and Gas Association stated that acceleration of sales would be useful in triennial sale areas, but would not be a satisfactory substitute for scheduling frequent sales in high interest areas.

- ARCO commented that the potential to accelerate sales should be available in all planning areas.

6. Environmental and Other Organizations (13)

The following comments were submitted directly to the Department of the Interior:

- The Marin Conservation League and the California Public Interest Research Group cited the flexibility provision in resolutions expressing general opposition to the Draft Proposed Program.

- The Environmental Center of San Luis Obispo County and Friends of the Sea Otter commented that the flexibility provision gives the Secretary of Interior too much discretion at the cost of State and local governments.

- Greenpeace, the Natural Resources Defense Council, and the Whale Center commented that the flexibility provision appears to be inconsistent with the OCS Lands Act.

- The League of Women Voters of San Luis Obispo commented that the flexibility provision would disrupt the entire planning process for OCS leasing.

- The League of Women Voters of Santa Barbara requested that the flexibility provision not be applied to leasing in the Santa Barbara Channel and the Santa Maria Basin.

- The Lone Star Sierra Club Chapter (Galveston, TX) commented that since economic conditions change much more rapidly than exploration and production activities, acceleration of leasing is not warranted.

- The Florida Public Interest Research Group commented that acceleration is acceptable, but deceleration should also be considered in the program.

The following comment was forwarded by the Governor of California's letter:

- The Planning and conservation league and the Pacific Coast Federation of Fishermen's Association commented that flexibility provisions should be the responsibility of Congress.

7. Private Citizens (7)

- The comments from private citizens expressed opposition to the flexibility provision.

8. Congress (1)

- A letter signed by Mel Levine, Bill Lowry, and Leon E. Panetta commented that the proposed flexibility provision may conflict with the Secretary's stated commitment to a slower leasing pace, orderly consultations, and early conflict resolution.

(ii) Frontier Exploration Sales

1. Federal Agencies (1)

- NOAA suggested that a supplemental studies program be established for planning areas in which frontier exploration sales are proposed.

2. State Governors (2)

- Maine expressed agreement with the concept of frontier exploration sales with a request for interest step and urged that the concept be applied to the North Atlantic planning area.

- New Jersey stated that they have no opposition to frontier exploration sales, but stated that the process for such sales must include consultation with the Governors of affected States.

3. State Agencies (0)

No comments on this topic were received.

4. Local Governments (0)

No comments on this topic were received.

5. Industry (3)

- Western Oil and Gas Association stated agreement with the proposal to include frontier exploration sales.
- Exxon commented that industry interest in each proposed frontier exploration sale should be established during annual review of the 5-year program, rather than adding the request for interest presale step.
- The American Petroleum Institute expressed support for the inclusion of frontier exploration sales, but commented that the sales should be considered "standard" instead of "tentative".

6. Environmental and Other Groups (0)

No comments on this topic were received.

7. Private Citizens (0)

No comments on this topic were received.

8. Congress (0)

No comments on this topic were received.

(iii) Supplemental Sales

1. Federal Agencies (1)

- The Environmental Protection Agency identified a need for timely communication on supplemental sales to allow adequate response to NPDES permit requests.

2. State Governors (4)

- Maine stated that the supplemental sale concept is reasonable.
- Massachusetts commented that the provisions pertaining to supplemental sales are vague and may be inconsistent with the OCS Lands Act.
- New Jersey stated that adequate consultation with affected States must be a part of the supplemental sale process.
- North Carolina questioned the statutory authority for supplemental sales and offered the following three suggestions: 1) no block should be offered unless it has gone

through an EIS process within the last five years; 2) consideration should be given to the need for a request for interest step in the prelease process; 3) guidelines and regulations should be developed before actually holding any supplemental sales.

3. State Agencies (2)

- The Senate Rules Committee of the California Legislature commented that California faces the likelihood of supplemental sales, and the overall pace of leasing is not slowed if such sales are included in the schedule.
- The California Department of Justice commented that addition of supplemental sales contributes to ambiguity regarding the timing of sales off California, thereby limiting effective notice as to when and where leasing and development will occur.

4. Local Governments (3)

- The City of Santa Barbara commented that supplemental sales will contribute to an annual leasing pace.
- The City of Pismo Beach and the county of San Luis Obispo noted supplemental sales in resolutions stating general opposition to the Draft Proposed Program.

5. Industry (8)

- Texaco, National Ocean Industries Association, Alaska Oil and Gas Association, Western Oil and Gas Association, and American Petroleum Institute endorsed the concept of supplemental sales.
- Shell commented that the provision for supplemental sales should be retained, but it would be an inadequate response mechanism if major discoveries are made.
- Exxon commented that supplemental sales would be more useful if broadened in scope.
- Amoco expressed a need for more information describing the supplemental sale provision.

6. Environmental and Other Groups (3)

- The League of Women Voters of San Luis Obispo commented that supplemental sales could speed up the leasing schedule.
- The League of Women Voters of Santa Barbara requested that no leases in the Santa Barbara channel or the Santa Maria Basin be offered in supplemental sales.

- The Natural Resources Defense Council commented that supplemental sales would disrupt the schedule and limit its value as a planning document.

7. Private Citizens (0)

No comments on this topic were received.

8. Congress (1)

A letter signed by Congressmen Mel Levine, Bill Lowry and Leon R. Panetta commented that the proposed supplemental sales provision may conflict with the Secretary's stated commitment to a slower leasing pace, orderly consultations, and early conflict resolution.

F. Whether conditions such as the following concerning the level of the minimum bid would warrant varying the current minimum bid level of $150 per acre on a nationwide or planning area basis: (1) changes in economic conditions such as oil prices; or (2) potential effects on the number of tracts leased or the rate of exploration and development.

1. Federal Agencies (1)

- The Department of Energy commented that they would support changes designed to encourage frontier exploration, but also observed that without compelling reasons to change the minimum bid level, it would be best to leave it as is for the sake of program stability.

2. State Governors (6)

- Alabama stated that the current minimum bid level is appropriate only for frontier areas and should be raised in high potential areas.

- Maryland commented that the minimum bid level should be adjusted, at least on a planning area basis, to take care of any contingencies that may arise.

- New Jersey communicated a willingness to explore with the Department of the Interior consideration of varying the current per acre bid level if it could be demonstrated that it would be an economic benefit to the Federal Government and encourage exploration.

- North Carolina stated no objection to raising the minimum bid level, but would object to lowering it.

- Rhode Island endorsed establishment of different minimum bids for different planning areas. They also suggested offering a limited number of tracts under a work commitment/fixed royalty bidding system.

- Virginia commented that the factors under consideration with this topic could have an effect on minimum bid level.

3. State Agencies (0)

No comments on this topic were received.

4. Local Governments (0)

No comments on this topic were received.

5. Industry (9)

- Chevron and Marathon commented that the current minimum bid is satisfactory for a 5,760 acre tract, but should be lowered for larger tracts.

- BP Alaska commented in favor of reassessing the minimum bid considering reduced expectations for future oil prices.

- ARCO encouraged elimination or reduction of the current minimum bid and recommended establishment of a minimum bid for each planning area at a level commensurate with exploration risk for that area.

- Shell recommended lowering the minimum bid in all planning areas and pointed out that the bonus bid represents just one element of the total revenue received by the Federal Government as a result of the OCS program. They also commented that the minimum bid level should be low to offset risks and costs in frontier areas and make leasing and developing those areas viable.

- Tenneco suggested halving the current minimum bid in the Gulf of Mexico to enhance the economic viability of prospects on which the potential for hydrocarbons is less than that of leases offered in previous sales.

- Sohio commented that generally the minimum bid level should be lowered, and recommended specific levels for certain planning areas and conditions.

- Texaco expressed opposition to the current minimum bid level and suggested that a range of $25 - $50 per acre be adopted on a nationwide basis.

- Exxon recommended that the minimum bid level be revised on a planning area and water depth basis. A figure of $50 per acre for Alaska planning areas and greater than 400' water depths was suggested, and a level of $75 per acre was suggested for the rest of the OCS.

6. Environmental and Other Groups (3)

   - The Lone Star Sierra Club chapter (Galveston, Tx.) stated that the minimum bid level should be tied to the economy by indexing, and difficulty factors such as deep-water and strong currents should be considered, but the minimum bid always should be enough to cover costs of the leasing program.

   - The Florida Public Interest Research Group and Greenpeace expressed opposition to lowering the minimum bid level.

7. Private Citizens (0)

   No comments on this topic were received.

8. Congress (0)

   No comments on this topic were received.

G. Whether the tract size limit of 5,760 acres ought to be expanded; and whether enlargement of the maximum tract size is an alternative which would achieve effects comparable to varying the minimum bid.

1. Federal Agencies (1)

   - The Department of Energy commented that they would support changes designed to encourage frontier exploration, but also observed that without compelling reasons to change the maximum tract size, it would be best to leave it as is for the sake of program stability.

2. State Governors (4)

   - Alabama stated that the maximum tract size should not be expanded for tracts in the 8(g) zone off Alabama, and sufficient data are not available to comment on expansion in areas beyond the 8(g) zone.

   - Virginia stated they have no reason to advocate a change in tract sizes at this time.

   - New Jersey communicated a willingness to explore with the Department of the Interior consideration of expanding the maximum tract size if it could be demonstrated that it would be of economic benefit to the Federal Government and encourage exploration.

   - North Carolina commented that expanding the maximum tract size may be appropriate for frontier areas, but not for highly productive areas.

3. State Agencies (0)

   No comments on this topic were received.

4. Local Governments (0)

   No comments on this topic were received.

5. Industry (9)

   - BP Alaska, Shell, Texaco, Amoco, and Exxon did not support expanding the maximum tract size. BP Alaska commented that larger tracts might lower competition. Shell recommended encouraging the formation of exploration units rather than leasing larger tracts.

   - Chevron, Sohio, and Mobil supported expanding the maximum tract size to tailor it to specific prospects. Chevron recommended sizes up to 23,040 acres in the Atlantic Reef Trend and West Florida Strait. Mobil recommended increasing the size of tracts in waters over 300 meters deep to 11,520 acres.

   - Marathon commented that a larger tract size may be appropriate in low interest areas or areas wh[illegible]tion and development costs are high.

6. Environmental and Other Organizations (2)

   - The Florida Public Interest Research Group stat[illegible] bjection to enlarging tract size to a reasonable economic [illegible]tion unit, providing the minimum bid level is raised t[illegible]ain the same price per acre.

   - Greenpeace expressed opposition to expanding the maximum tract size.

7. Private Citizens (0)

   No comments on this topic were received.

8. Congress (0)

   No comments on this topic were received.

H. Whether there are subareas within planning areas which should be subject to special considerations, either in the presale planning process for each sale or, more generally, within the 5-year program itself, and what those considerations should be.

1. Federal Agencies (4)

- NASA requested the deferral of some 380 blocks from the Mid-Atlantic planning area to eliminate the possiblity of an exploratory rig and/or production platform being damaged by falling debris from rocket and missile tests.

  In the South Atlantic planning area NASA requested that a surface-free area be set aside (within the area from 31.61 N., 79.036 W., to 27.13 N, 77.34 W) for space shuttle launches, for other DOD/NASA missile and space vehicle launches, and for Navy submarine operation and launch activities. They also stated their position that no fixed structures should be permitted in the water off Kennedy Space Center in any direction for a distance of 70 nautical miles, and none should be permitted within the potential Solid Rocket Booster and External Tank footprints for either nominal missions or Return to Launch Site aborts.

- The Department of Defense stated that any area which they use should be more prominently displayed in the leasing plan so that identification and resolution of specific potential conflicts during the presale process will be easier.

- The Coast Guard discussed Precautionary Areas, Traffic Lanes and Fairways, and commented that any leasing activity must recognize navigational safety and vessel routing measures as a limiting factor in offshore development.

- The Department of Energy commented that no subarea should be deleted from consideration until an adequate evaluation has been made of the oil and gas resource potential of the area.

2. State Governors (12)

- Alaska requested removal of the North Aleutian Basin lease sale from the Draft Proposed Program schedule and stated that no oil or gas leasing should occur near Unimak Pass. They also requested deferral of tracts near the Pribilof Islands, within 12 miles of the Yukon Delta, and in traditional subsistence hunting areas in close proximity to Pt. Barrow.

- California included a summary of comments which the Governor received from State agencies, local governments, oil industry, organizations, and individuals. These comments are summarized in this appendix under their respective headings.

- Delaware stated that submarine canyonheads in the Mid-Atlantic planning area are subareas of special concern. They also requested deferral or deletion of tracts within 12 miles of Delaware's territorial waters (within 15 miles of the coast).

- Florida recommended permanent removal of the NASA/DOD Flight Clearance Zone from the South Atlantic planning area and commented that areas South of 25° N latitude to 24° latitude and east of 82° W longitude in the Eastern Gulf of Mexico planning area should not be in the leasing program.

- Maine requested removing the Gulf of Maine from the North Atlantic planning area because of the absence of suitable geology.

- Maryland made no specific deletion requests, but cited subareas of special concern, e.g., litigation and modifications to the Sale No. 76 area and the 50-mile buffer in proposed Sale 111 in the Mid-Atlantic.

- Massachusetts stated that the high biological productivity of the Georges Bank region makes it environmentally unacceptable to allow oil and gas leasing, the Gulf of Maine should be removed from further consideration for leasing activity, and the area encompassed by the 400-meter isobath and submarine canyons should be removed.

- New Jersey commented that they will not support the offering of tracts within 50 miles of their coast, nor within canyon systems which have high environmental sensitivity and are important to commercial fisheries. They stated that they seek to eliminate all tracts within 50 miles of the coast in the Mid-Atlantic and North Atlantic Regions, and seek possible exclusion of canyon systems and other productive fishing grounds during presale planning on individual lease sales.

- North Carolina endorsed the subarea deletion concept and suggested that areas which can be excluded without much controversy should be deleted from the 5-year program. Such areas might include shipping lanes, submarine lanes, ocean disposal sites, offshore national defense areas, NASA Flight zones, National Marine Sanctuaries, and areas affected by international boundary disputes. Consideration should be given to deleting the area shoreward of the 200-meter isobath off North Carolina and designating a buffer zone around the Monitor Marine Sanctuary which would exclude leasing. Exclude two sites being analyzed and considered for the national marine sanctuary program: the inner shelf (Ten Fathom Ledge), 17 miles south of Cape Lookout, N.C., and the outer shelf (Big Rock), 36 miles offshore. They also wanted canyonhead areas to be excluded and studies on the outer shelf and edge live bottom complex to be conducted to determine candidate sites for exclusion.

- Oregon suggested that the area of the proposed Washington-Oregon planning area which is seaward of 125° W be deleted, as well as Heceta, Stonewall, and Perpetua Banks.

- Rhode Island commented that certain subareas must receive special consideration, but they should be addressed on a sale by sale basis.

- Virginia requested deletion of areas within 50 miles of the coastline.

3. State Agencies (5)

- Jack O'Connell, Assemblyman California Legislature, requested removal of the proposed Southern California tracts from the current 5-year plan at least until all of the existing leases have been explored thoroughly enough to indicate how much oil will be processed in Santa Barbara from these leases.

- The Senate Rules Committee of the California Legislature recommended deletion of (1) all tracts within the Point Reyes-Farallon Islands, and Santa Barbara Channel Islands National Marine Sanctuaries; (2) all tracts in the Santa Barbara Ecological Preserve and Buffer Zone; (3) all tracts within and immediately adjacent to Santa Monica Bay; (4) all tracts within the access routes to the Ports of Los Angeles, Long Beach and San Luis; (5) all tracts with a 6-mile buffer zone from the San Diego County/Mexican boundary to Newport Beach in Orange County; and (6) tracts north of the Santa Maria River.

- The California Coastal Commission recommended deferral of tracts in the Santa Barbara Channel, deletion of some tracts off the Los Angeles and Ventura Border, deletion of some fisheries tracts south of Santa Rosa Island, deletion of tracts offshore San Diego, deletion of tracts within six nautical miles of Catalina Island, and deletion of tracts within Marine Sanctuaries and Federal oil and gas reserves.

- The California Department of Justice favored deletion of areas in the Santa Barbara Channel, Santa Monica Bay and the OCS adjacent to Southern Orange County and San Diego County.

The following comment was forwarded by the Governor of Oregon's letter:

- The Department of Geology and Mineral Industries identified the following subareas within the Washington-Oregon planning area to be given special consideration: geologic hazard areas; OCS blocks adjacent to state waters, shipping lanes, dumping areas for dredge spoils, and especially productive fisheries such as Heceta Bank and Stonewall Bank.

4. Local Governments (25)

The following comments were submitted directly to the Department of the Interior:

- The City of Los Angeles cited areas under current moratorium, but did not actually nominate any subareas for deletion.

- The County of Santa Cruz made comments similar to Los Angeles.

- The City of Laguna Beach requested a permanent moratorium applying to the waterway between the south Orange County coastline out to Catalina Island.

- The City of Oceanside stated that leasing in the San Diego area should be severely restricted, particularly in the near shore area.

- The City of Santa Barbara requested no additional leases in the Santa Barbara Channel/Santa Maria Basin Region, no additional leases in Marine Sanctuaries and Federal Oil and Gas Preserves, and no additional leases in Congressional moratorium tracts.

- The City of Pismo Beach and the City of Morro Bay requested no additional leasing within the subarea north of the Santa Maria River.

- The County of San Luis Obispo stated a desire to preclude leasing north of Morro Bay, provide a 20-mile buffer around Morro Bay, and provide a 12-mile buffer from the sea otter range.

- The San Diego Association of Governments recommended deletion of (1) the area on tracts offered in previous lease sales that have not been bid; (2) the sensitive nearshore areas currently covered by the Congressional moratoria offshore Southern California; (3) the military training and operating areas that were identified by the DOD in its letter of August 18, 1983; and (4) offshore areas which have water depths greater than 400 meters (until proven production technology has been developed for use in the nearshore areas).

- The City of San Clemente commented that they consistently have voiced opposition to the inclusion of Southern California nearshore areas for exploration and drilling programs, and have consistently supported legislative moratoria in nearshore areas.

- The County of Monterey (2nd District Supervisor, Barbara Shipnuck, in a statement to Secretary Gordon Duffy) recommended deletion of the waters north of the Santa Maria River including the Eel River, Bodega, Point Arena, Santa Cruz, and Northern Santa Maria Basins; tracts within 6-nautical miles of Catalina Island; Santa Monica Bay ; some tracts off the Los Angeles and

Ventura border; some fisheries tracts south of Santa Rosa Island; tracts offshore San Diego; and tracts within marine sanctuaries in Federal oil and gas reserves. Deferral was requested for tracts within the Santa Barbara Channel until cumulative impact problems can be resolved. Other locations, including the waters off Big Sur and Monterey Bay, were cited as examples of subareas which should have been excluded from the 5-year program.

Karin Strasser Kauffman, 5th District Supervisor (in a statement to Secretary Gordon Duffy), supported prohibiting oil and gas development in the OCS off Big Sur and off Monterey County.

- The City of San Diego expressed opposition to efforts to develop petroleum and natural gas resources in waters within 100 miles of the San Diego coastline. They recommended deleting areas offered and not bid upon in previous lease sales off San Diego; areas deleted in previous lease sales; the area covered by Congressional moratoria off San Diego from Sale 95; and areas with water depth greater than 400 meters in Southern California (until proven technology is developed).

- The City of San Clemente expressed support for legislative moratoria in nearshore areas off Southern California.

- The County of Ventura recommended deletion of the Channel Islands National Monument and Marine Sanctuary and tracts within the Channel Islands shipping lanes.

- The City of Watsonville expressed support for the Congressional OCS drilling moratoria.

- The City of Santa Cruz expressed support for the continuation of a moratorium on OCS exploratory and development activities within California coastal areas.

- The County of Santa Barbara requested deletion of the Santa Barbara Channel and Santa Maria Basin from the two southern California lease sales now scheduled for 1987 and 1990 until the County has the results from impact monitoring programs now in progress as assurances that additional production can be accommodated within local offshore and onshore resource constraints and in a manner consistent with County long-range goals.

- The City of Santa Monica requested the exclusion of Santa Monica Bay from the leasing program and defined Santa Monica Bay as the area landward of a straight line drawn from Point Dume to the Tip of Palos Verdes Peninsula. They stated that drilling should be prohibited for three full miles west of that line.

The following comments were forwarded by the Governor of California's letter:

- The City of Lompoc requested deletion of the Santa Barbara Channel and Santa Maria Basin until: the County has developed or revised pertinent programs and policies; additional production can be accommodated within resource constraints and long-range goals; and existing and future lessees are required to comply with air quality standards equivalent to those for onshore sources.

- The City of Oceanside commented that leasing near the shore of San Diego should be restricted.

- The City of Palos Verdes Estates requested deletion of Santa Monica Bay.

The following comments were forwarded by the Office of the Governor of Florida:

- The South Florida Regional Planning Council stated that those areas with insufficient environmental data, areas with seagrass beds, areas with coral reefs, and areas south of 26° North latitude should not be part of the leasing program.

- The County of Volusia, Florida stated that if a memorandum of understanding has been signed by DOI/NASA/DOD regarding deleting certain tracts in the South Atlantic area because of flight clearance zones, then the deletions should be reflected in future offerings.

- The Tampa Bay Regional Planning Council commented that extensive seagrass beds in shallow waters south of 26° N Latitude should be protected by attaching a photodocumentation stipulation on leases offered in the area.

5. Industry (7)

- Chevron commented that portions of the Southern California planning area which are used for defense activities may require special consideration.

- Marathon stated that certain subareas should receive special consideration, but they should not be excluded from lease sales.

- Shell, Exxon, and Amoco stated opposition to establishment of special subareas subject to special considerations.

- Mobil and Sohio commented that frontier and deepwater areas or subareas should be given special treatment based on consideration of drilling results, economics, technology, and needs.

6. Environmental and Other Groups (14)

- The League for Coastal Protection recommended deletion of those areas off Southern California from Lease Sale 95 presently covered by Congressional moratoria.

- The League of Women Voters of San Luis Obispo requested deletion of all areas in the Northern Santa Maria Basin north of the Santa Maria River, consistent with previous Coastal Commission and local government comments.

- The League of Women Voters of Santa Barbara called for protection of marine sanctuaries in the Santa Barbara Channel, and recommended deletion of the Santa Maria Basin and the South Coast area.

- The San Francisco Bay Sierra Club Chapter expressed opposition to the leasing of offshore areas above the line demarcated by the Santa Maria River.

- Friends of the Sea Otter requested deletion of all tracts in the southern California planning area north of the Santa Maria River as well as those presently covered by provisions of the FY 1984 Appropriations Act.

- The Sierra Club Lone Star Chapter (Galveston, Texas) requested that special consideration be given to subareas including all biologically sensitive areas; marine sanctuaries and proposed sanctuaries within a minimally 4-mile protective zone; fishing banks; and fairways, ports such as LOOP, and areas where bottom-surface-minerals might be harvestable.

- The Whale Center, stated support for deletion of Santa Monica Bay, all tracts within Marine Sanctuaries, and all Federal oil and gas reserves.

- Get Oil Out Inc. commented that no sales should be planned for the Santa Barbara Channel until such time as all present leases have been inventoried, all development plans are in place, and all plans for accommodating the anticipated oil by onshore facilities have been completed and are in place. Further deletion requests included all tracts contained within the Channel Islands Federal Marine Sanctuary, as well as all tracts within the Santa Barbara Ecological Preserve and associated Buffer Zone off the coast of Santa Barbara, California.

- The Massachusetts Audubon Society stated that within the North Atlantic planning area, tracts located in depths shallower than 400 meters and submarine canyon tracts should be permanently deleted from future lease sales.

- The Natural Resources Defense Council urged deletion of the areas under moratorium when the Draft Proposed Program was released, as well as areas off Alaska and along the Washington/Oregon coast.

- Greenpeace recommended deletion of Georges Bank in the North Atlantic; areas off the Gulf Coast of Florida; the four northern basins in the Northern and Central California planning areas, plus a buffer zone in the Santa Maria Basin to protect the southern sea otter range; portions of the Southern California planning area, such as Channel Islands Marine Sanctuary; Bristol Bay; and a buffer on Unimak Pass.

- The Democratic Central Committee, Mendocino County, stated support for efforts to stop all offshore oil related activities including leasing in the sensitive areas of southern, central, and northern California.

The following comments were forwarded by the governor of California's letter:

- Greenpeace Pacific Southwest commented that leasing should not take place in the moratorium areas of Southern California; Federal ecological preserves, sanctuaries, or buffer zones; certain areas off Los Angeles and Ventura Counties; sensitive fisheries tracts off Santa Rosa Island; within six miles of Catalina Islands or North of the Santa Maria River. They further commented that leasing in the Santa Barbara Channel should be deferred until the cumulative impacts of existing leasing are evaluated.

- The Santa Lucia Sierra Club Chapter stated that no leasing should occur north of Pismo Beach to Monterey or from Pismo Beach to Carmel.

7. Private Citizens (8)

- Comments submitted by private citizens requested deletion or special consideration of specific subareas which have been identified and described above by other commenters.

8. Congress (1)

- A letter signed by Mel Levine, Bill Lowry, and Leon E. Panetta expressed a desire to reach a long-term resolution of the status of sensitive areas off California.

V. SUMMARY OF COMMENTS ON APPENDIX P--IN RESPONSE TO FEDERAL REGISTER NOTICE OF AUGUST 19, 1985

On March 21, 1985, an initial version of the Secretarial Issue Document (SID) for the Draft Proposed 5-Year OCS Oil and Gas Leasing Program was issued. Based on comments received on Appendix P, "Analysis of Tract Selection and Areawide Leasing Approaches," to the SID, a Federal Register Notice was published on August 19, 1985, to request further public comment. These comments, which are summarized below, will be considered and discussed in the next revision of Appendix P.

Respondents from the oil and gas industry indicated agreement with the analysis and conclusions of Appendix P and stated support and endorsement of the areawide leasing program. Two of these respondents believe the program to be in line with Congressional mandates calling for expeditious OCS exploration and development and receipt of fair market value. One respondent states that areawide leasing allows explorationists to proceed in a more logical manner through the appraisal of technical data over a large area. Two respondents also note that it is more beneficial from both a financial view and in the national interest to make many large discoveries sooner. The resultant economic benefits from royalties and taxes will be of more value if finds are more rapidly developed. Areawide leasing affords this.

Respondents from State agencies and the Natural Resources Defense Council (NRDC) voiced opposition to the areawide leasing program for several of the reasons that the oil and gas industry support it. As previously stated, industry feels areawide leasing affords compliance with Congressional mandates, improved exploration, more rapid discovery and development, and increased economic benefits. However, the Attorney General of Texas commented that the areawide selection process has failed to achieve the return of fair market value and believes the conclusions arrived at in Appendix P to be highly suspect or without merit. The Attorney General of Texas and one other respondent also contend that the areawide leasing approach is illegal, contrary to the language and intent of the OCS Lands Act, and fails to comply with its mandates. One respondent believes that the huge offerings permitted by areawide leasing dilute the quality of information available to balance the risks of development with the potential oil and gas benefits. The Louisiana Geological Survey supports a steadier, paced leasing program. The NRDC commented that the rapid development of areawide leasing does not sequence development so that each lease sale is timed to benefit from new geological data for adjacent OCS properties, which leads to inefficient exploration investments and higher costs. Contrary to industry's belief that areawide leasing affords more rapid development of OCS discoveries, the NRDC believes that the pace of development is not guaranteed to increase over what would occur under a more selective tract selection approach. The summary of comments from all respondents follows:

A. Federal Agencies

Department of Energy (DOE)

The DOE concluded that areawide leasing has increased the present value contribution of total OCS payments to federal revenues by about $3.5 billion compared to tract selection. Areawide leasing has allowed more rapid exploration and development of OCS resources and increased the present value of federal OCS revenues. Areawide leasing has increased domestic oil and gas production, reduced imported oil consumption, and increased domestic economic growth. The DOE review of the July 15, 1985, GAO study, "Early Assesment of Interior's Areawide Program for Leasing Offshore Lands," uncovered significant errors that led GAO to reach incorrect conclusions. The DOE provided detailed discussion on this issue.

B. Governors

The Governors were generally supportive of OCS leasing but predominantly questioned the use of data from the GOM as a basis for comparing and contrasting areawide leasing with tract selection leasing for frontier areas.

1. Connecticut

- Questions the relevance of using the experiences of a mature producing area with an historical tolerance of and economic dependency on the offshore oil business (GOM) to compare and contrast areawide leasing with tract selection methods.

- Issues of investment, revenue and fair market value will remain moot in the North Atlantic until a reasonable settlement to provide adequate environmental safeguards as well as meaningful incentives for industry exploration efforts can be reached.

- The standardization of planning areas and leasing programs among mature and frontier areas may not be a workable concept.

2. Maryland

- Observes most data were derived from the GOM experience where leasing, drilling, production, transportation and refining activities are performed in a mature petroleum province.

- The areawide concept is more acceptable in the GOM than in a frontier or semi-explored area such as the Atlantic OCS for several reasons:

  - Three decades of exploration and production in the GOM have produced a wealth of sub-surface data giving the explorationist a higher degree of certainty of finding producible reserves;

- Regional residents are accustomed to oil and gas activities from exploration to refining and welcome the industry; and

- Oil and gas drilling began on land and gradually went from shallow inland waters to open Gulf waters, so near-shore drilling is accepted.

° The local Mid-Atlantic population has no experience with coastal oil and gas wells and perceives such exploration as a threat to their life style and environment.

° Encourages oil and gas exploration on the Mid-Atlantic OCS but requests a 50-mile buffer zone where tracts would not be leased, due in part to areawide leasing. Areawide leasing does not allow assurable judgement of the general leasing area prior to the lease sale.

° Suggests using the areawide leasing concept for tracts over 50 miles offshore and the tract selection leasing concept for tracts less than 50 miles offshore.

C. State Agencies

Comments from two States indicated that Appendix P does nothing to change their opposition to areawide leasing. The California Secretary of Environmental Affairs felt that Appendix P provides little relevancy to California offshore leasing as it is based mostly on GOM data. The Louisiana Geological Survey's Department of Natural Resources expressed concern over the detrimental effects of an accelerated areawide leasing approach and promotes a steady, paced leasing program. The Maine State Planning Office believes Appendix P to be too much of a response to critics of areawide leasing and not enough of a policy analysis; there was no discussion of focused leasing, which is supported by the Governor of New Jersey. The Attorney General for Texas generally expressed that areawide leasing/promising acreage lease selection approaches are contrary to the language and intent of the OCS Lands Act and provided supporting legislative background for the nomination process.

Secretary of Environmental Affairs, California

° In its present form, the revised appendix does not have sufficient information to evaluate the merits of areawide leasing as it relates to leasing offshore California. It does not contain preliminary statistical results and relies on analysis that is based almost wholly on GOM data, with little information specific to the areawide leasing consequences for California.

° The revised appendix does not address the implications of areawide leasing to the value of bonus bids.

° The trade-off between lower bonuses and earlier receipt of royalties is not consistent with state and local government goals.

° The revised appendix indicates that the bonus portions of escrowed 8(g) funds from areawide lease sales are lower than if they had been from a tract selection approach. If the same method of revenue sharing is applied to future lease sales, the findings suggest that state and local interests will continue to be poorly served.

° The revised appendix provides further argument for the need to include royalties in any 8(g) settlement. It is only fair that the federal government share the compensating benefits that come only from the earlier receipt of royalties.

Department of Natural Resources, Louisiana Geological Survey

° The appendix does nothing to alter concerns for the potential negative economic and environmental impacts of the concentration of accelerated areawide leasing and development in the Central and Western Gulf.

° It appears DOI is ignoring that the short-term solutions for the nation which are detrimental to the states could become a national problem in the long run. A steady, paced leasing program would be the best interest of Louisiana and the nation.

° Concerns were expressed that data interpretation may be skewed toward DOI's viewpoint and that there was a lack of adequate test and analysis results in this report.

° The Department of Natural Resources did not necessarily agree that average bids per acre had already been declining and therefore, had not been effected by areawide leasing. Provided background indicating that bids have fluctuated since the program's beginning and therefore, it does not appear that generalities and conclusions regarding bid trends can be made.

° Louisiana remains a proponent of a paced leasing program.

State Planning Office, Maine

° The State Planning Office felt the document was too much a response to critics of areawide leasing and not enough of a policy analysis and provided the following reasons:

- No alternatives to tract selection and areawide leasing were identified; there was no discussion of focused leasing.

- The appendix's appraisal of tract selection procedures was clearly negative, but the case made against tract selection was mixed at best:

  + Nowhere was it mentioned that the oil industry had (usually very significant) input to the process;

+ The main advantage described for areawide leasing could as easily been said about tract selection, i.e., if a company had information about a desirable lease area and communicated it to the Department, the tract(s) could be included in a sale; and

+ It may be that the limitations of the old fair market value evaluation procedures increased the probability that a tract receiving one nomination would be dropped, but this is a function of fair market value procedures, not tract selection or areawide leasing.

- The analysis points to potentially significant differences between the GOM and frontier areas. A different set of responses to the prospect inventory for frontier areas was hypothesized, but nowhere were these implications made clear.

° The effects of expanded interest into deep water in the Gulf were not fully evaluated; water depth was not systematically treated as a potential intervening variable.

° The conclusion that leasing was expanding under areawide leasing even though oil company profits were declining is another potential problem. The State Planning Office would be hesitant about linking profits with exploratory budgets within any one year.

° More detail on the studies already done and prospects for additional analysis on the relationship between high bids and leasing procedure would be helpful.

Massachusetts Coastal Zone Management Office (MCZM)

° Massachusetts is opposed to areawide leasing and believes that areawide leasing is illegal, that it places an enormous administrative burden on the States and Federal Government, and that it makes a mockery of the environmental review process.

° The MCZM Office expressed concern that although almost every state that commented on the Draft Proposed 5-Year Program issued in March 1985 expressed opposition to areawide leasing and raised many administrative and environmental concerns similar to those of Massachusetts, these issues were not dealt with in draft Appendix P.

Department of Environmental Protection, New Jersey

The Department's technical review of the document in no way changes the Governor's position of support for Secretary Hodel's proposal for "focused leasing," an improved approach that clearly identifies areas of highest industry interest and eliminates environmentally sensitive areas early in the planning process.

Office of Marine Affairs, North Carolina

Nothing in the revised appendix alters concerns with the areawide leasing approach, the concept of which is opposed due to environmental planning considerations. The huge offerings permitted by areawide leasing dilute the quality of information available to balance the risks of development with the potential oil and gas benefits. Areawide leasing reduces the ability to assess and plan for the adverse environmental and socioeconomic impacts associated with offshore development.

Attorney General of Texas

° The Attorney General submitted from a legal viewpoint and technical analysis that the areawide leasing process is inherently illegal and an economic failure.

° The Attorney General expressed that the Secretary of the Department of Interior has failed to comply with mandates of the Outer Continental Shelf Lands Act (OCSLA) by abandoning the nomination or tract specific selection process for the areawide selection process.

° Texas submitted that the OCSLA does not authorize the Secretary to use an areawide leasing selection approach or the new conceptual version of a promising acreage approach; the OCSLA specifically requires the use of a leasing selection system which employs the nomination of specific tracts designed to obtain fair market value.

- Texas offered illustration that there is no substantive difference between areawide leasing and the concept of promising acreage.

° The Attorney General expressed that areawide leasing/promising acreage lease selection approaches are contrary to the express language and intent of the OCSLA, and provided supportive definition and legislative background for the term "nomination."

° The Attorney General commented that the areawide selection process has failed to achieve the return of fair market value. The conclusions set forth in Appendix P for fair market value are highly suspect or without merit.

° Comments expressed concern that there is overwhelming evidence that areawide leasing has totally frustrated at least two goals set forth in the OCSLA amendments:

- Achievement of a fair return for OCS lease sales; and

- Preservation and maintenance of competition.

- Comments expressed concern that the federal government and the coastal states receive less revenues under areawide selection procedures and under the DOI geometric average criterion in which DOI gives more weight to a relative fewer number of bids (because of averaging) than its own estimates of tract value.

  - Comments concluded that DOI's arbitrary practice of offering all unleased tracts makes it impossible for the federal government to evaluate tracts meaningfully both inside and outside of the 8(g) zone.

- Concern was expressed because the requirement of furnishing coastal State Governors with specific data under 43 U.S.C. 1337(g)(1) is not being met by the areawide/promising acreage leasing approach.

  - Texas submitted that MMS has failed or otherwise refused to provide necessary geological and geophysical data, other than data associated with the MMS unilateral decision on common geological structures.

- Texas recommended that DOI use neither the promising acreage concept nor the areawide leasing selection procedure for lease sales since the OCSLA requires use of a nomination selection process for OCS lease sales.

  - Texas concluded that DOI's use of the areawide selection process to implement the 5-Year Program or any specific lease sale, instead of the nominations selection process, is contrary to the OCSLA and invalid.

The Attorney General of Texas submitted the affidavits of Dr. Jeffrey J. Leitzinger, a Senior Consultant with National Economic Research Associates, Inc., and Dr. Joseph Stiglitz, Professor of Economics, Princeton University as attachments to his comments.

1. Affidavit of Jeffrey J. Leitzinger

° Dr. Leitzinger offered the following conclusions with the appropriate supporting data:

  - Average cash bonus payments per acre declined substantially with the changeover to areawide leasing. This occurs in OCS sales nationwide, the GOM, offshore Texas and tracts in the Texas 8(g) zone.

  - The decline in per acre cash bonuses does not appear to be attributable to increased water depth.

  - The decline in per acre bonuses does not correspond to declining expected resource amounts. Bonuses per unit of resources (taken from pre-sale estimates) show declines similar to those reflected in per acre bonuses.

  - The decline in bonuses does not appear to be due to changing energy prices. "Constant-energy price" bonuses show even more pronounced declines with the onset of areawide leasing than do nominal per acre bonuses.

  - The decline in bonuses was accompanied by an increase in the frequency of single-bid tracts.

  - Despite substantial increases in both acreage and resource offerings with the changeover to areawide leasing, total bonus bids showed only a modest increase.

  - These results suggest that lower areawide bonuses are attributable to the combined effects of greatly increased volumes of acreage offered, limited resources employed by bidders for purposes of tract evaluation and bidding, limited pre-sale information and reduced competition.

° Dr. Leitzinger described several factors which point to reduced competions as a likely cause of declining bonuses subsequent to the adoption of arewide leasing.

2. Affidavit of Dr. Joseph Stiglitz

° Dr. Stiglitz commented that there is indication that Interior itself has been skeptical about the results of areawide leasing and provided an excerpt from the Gulf of Mexico Summary Report, September 1983, Outer Continental Shelf Oil and Gas Information Program.

° Dr. Stiglitz concluded that if the policy of increased production from offshore leasing is viewed to be a desirable one, such an objective can be obtained at less cost to the taxpayers by a slight modification of the nomination system simply by increasing by a relatively small amount the fraction of nominated leases put up for bid.

° Dr. Stiglitz included supporting data for the premises that areawide leasing depresses bonus payments by reducing competition and that areawide leasing should not have an effect on the pace of hydrocarbon production.

Deputy Secretary for Resources, Virginia

Since the additional material included in Appendix P deals only with the Central and Western planning area of the GOM and involves no Virginia offshore resources, no comments were offered beyond those for the 5-Year OCS Leasing Program itself.

D. Local Governments

E. Environmental and Other Interest Groups

Natural Resources Defense Council (NRDC)

NRDC's comments consist of two separate sets of comments. One set of comments was prepared by James Love and Joseph Stiglitz; the second set of comments was prepared by Dr. Michael Kavanaugh.

° Comments Prepared by Messrs. Love and Stiglitz

The key assumptions that the Appendix P analysis is based upon include a revised assumption about the future path of oil prices, the delay in development from a tract selection leasing program, and the social rate of discount.

The path of oil prices is an important issue in the evaluation of the pace of a leasing program. The new version of Appendix P appears to place a greater weight on the view that long term oil prices are stable or falling. This assumption is used to buttress the DOI contention that all OCS development should proceed as rapidly as possible. While the past few years have seen a decline in real oil prices, this is hardly conclusive proof that the trend will continue over the relevant time period for OCS development. Oil prices have historically tended to move upward in spurts, followed by stable prices or declines, than renewed price surges. Supporting examples of this are provided. In their discussion of long term oil prices, Messrs. Love and Stiglitz commented that a major shortcoming of areawide leasing is that it does not sequence development in such a way that each lease sale is timed to benefit from new data on the geology of adjacent OCS properties. This leads to inefficient exploration investments and higher costs.

The areawide program only guarantees that property rights are rapidly transferred. It does not guarantee that the pace of development will be substantially increased over what would occur under a more selective tract selection procedure.

Messrs. Love and Stiglitz commented that for the third assumption used in Appendix P, the rate of discount used to time development and value future lease receipts, DOI made a methodological error in calculating the eight percent discount rate used throughout the Draft 5-Year Plan. They submitted illustrative support for these comments and provided discussion of the further modeling they undertook to analyze the cash bonus and net profit share methods. They submitted that the profit sharing method does not suffer from any of the alleged shortcomings of the royalty bid method, and it is difficult to understand why profit sharing is not widely used by DOI. They further discussed drawbacks of the cost bonus bid system. They concluded that concerns about the leasing method endorsed in the Draft 5-Year Plan further convince them that the Federal Government should immediately scale back its leasing program. Appendix I to their comments provided more detailed discussion of their modeling. Appendix II is a transcript of Mr. Love's August 5, 1985, statement on the shortcomings of the DOI 5-Year OCS Leasing Plan given before the House Committee on Merchant Marine and Fisheries, Subcommittee on OCS and Panama Canal.

° Comments Prepared by Dr. Michael Kavanaugh

Dr. Kavanaugh commented that while the decision to lease using either a tract selection or an areawide approach is important, an equally important decision involves the areas Interior includes in the 5-Year Program. Interior acknowledged the importance of these location decisions in the earlier version, but this acknowledgement has been deleted from the revision. Dr. Kavanaugh stated that his analysis of the 5-Year Plan and the work of Professor Stiglitz indicated that some areas should not be included in the program.

DOI's acknowledgement that areawide leasing changed the method of conduct for environmental impact analyses has now also been deleted. He stated that the environmental effects should not be overlooked.

DOI has not been able to refute the evidence that areawide leasing caused the decline in bonus bids and the increase in one and two bid tracts that is evident.

The Executive Summary statement that areawide leasing has increased the total return to the U.S. Treasury perhaps by $8.5 million per tract is not supported by the analysis DOI presents in the body of the appendix. Dr. Kavanaugh provided discussion on why computations conducted by DOI have an upward bias.

F. Oil and Gas Industry

Comments received from the oil and gas industry indicated agreement with the arguments and conclusions of Appendix P and support and endorsement of the areawide concept. They submitted that areawide leasing has been a major catalyst for increased OCS exploration and development. Two respondents also offered discussion of the fair market value issue.

1. Amoco Production Company

Amoco strongly agrees and concurs with the conclusions under the analysis contained in Appendix P. Amoco's increased participation in the exploration and development activity in OCS areas is a direct result of the areawide leasing concept and supports conclusions for the increased rate of exploration investment and commitment necessary to evaluate those leases.

Commented that while tract bonus values may have decreased with the decline in oil and gas prices, perhaps these values reflect the quality of the acreage available in the more mature areas, such as the Central and Western GOM, as well as the lack of success in the Atlantic and certain Alaskan areas.

Amoco strongly endorses the areawide concept and urges its continuance to help expedite production.

2. Atlantic Richfield Company (ARCO)

ARCO agrees with both the propriety of the analytical methodology used and the validity of the conclusions. Continues to believe that energy and economic security demands an effective market-driven OCS oil and gas leasing program containing broad offerings in each OCS planning area.

3. Phillips Petroleum Company

Phillips supports areawide leasing and believes that the program has met the Congressional mandate of the OCS Lands Act Amendments of 1978.

They believe areawide leasing has resulted in increased offshore leasing capital investments, exploration, and production by industry which, in turn, has increased U.S. Treasury revenues because:

* Areawide leasing has resulted in a more expeditious and thorough evaluation of federal offshore oil and gas resources;

* Areawide leasing has encouraged innovative exploration strategies and technology which were not developed under the previous tract selection procedure; and

* Areawide offerings have provided a more flexible leasing approach which responds to the results of offshore exploratory drilling activity. This allows more efficient use of exploration information as the most promising areas may be reoffered as frequently as every two years.

4. Sohio Petroleum Company

Sohio supports the arguments developed in Appendix P but notes that exploration under the areawide leasing system has only been operative for two years, and this may be too short a time to compare its merits to those of the tract selection system.

Sohio submits that areawide leasing gives maximum exposure to high risk areas where such exposure is usually necessary to achieve success; it enables discoveries to be made and momentum to be established. They suggest that this is just as important as the question of fair market value for lease bonuses.

Sohio considers the fair market value arguments of Appendix P to be valid and regarding reduced competition, believes that more emphasis could be placed on the impact the new high risk and high cost plays has had on this.

Future areawide sales may not make so dramatic an impact as the most obvious attractive acreage has already been offered and new plays will generally be in more high-risk, costly, and remote environments. However, areawide leasing will still offer the enterprising and innovative explorer the opportunity to test new ideas that will maximize OCS potential in a timely manner.

5. Texaco USA

Texaco endorses the areawide leasing approach and believes its objectives are consistent with Congressionally-mandated directives. Texaco disagrees with some parties raising questions as to whether the Federal Government is receiving fair market value. Texaco's opinion is that GAO and others have assumed cause and effect relationships where none exist. Statistical analyses of bidding and leasing data do not reveal all factors at issue, and the comparisons do not present a true evaluation.

Texaco offers several factors which affect the number and amounts of bids and states that they could have substantial impact on the attractiveness of a tract to prospective bidders. They submit that GAO's inquiry into what constitutes fair market value should be broadened.

Where helpful suggestions, including those of GAO, have merit, they should be carefully considered and appropriately implemented. Texaco hopes that energies will be concentrated on reducing impediments and adopting a consistent, realistic OCS leasing approach.

APPENDIX C

LAWS, GOALS, POLICIES, AND COASTAL ZONE MANAGEMENT PROGRAMS OF AFFECTED STATES

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LAWS, GOALS, POLICIES, AND COASTAL ZONE MANAGEMENT PROGRAMS OF AFFECTED STATES

I. Introduction

Section 18 of the Outer Continental Shelf (OCS) Lands Act, as amended, requires the Secretary of the Interior to consider several factors in preparing and maintaining the 5-Year OCS Oil and Gas Leasing Program. These factors include: 1) the laws, goals, and policies of affected States which the Governors of those States specifically identify as relevant to the leasing program [18(a)(2)(F)]; and 2) the coastal zone management programs being developed or administered by affected States [18(f)(5)]. A letter from the Secretary dated July 5, 1984 requested the Governors of affected States to identify such issues, and their responses have been considered in developing the 5-Year Program. All issues identified by the Governors were presented in Appendix C of the Draft Proposed Program (March 1985).

The Secretary sent a copy of the Draft Proposed Program to each affected State Governor with a letter dated March 19, 1985, which solicited comments concerning that stage of the program and the development of the next stage, the Proposed Program. Eight responses identified relevant laws, goals, and policies or cited coastal zone management programs for the Secretary's consideration.

II. Laws, Goals, and Policies Identified by Governors

These matters were presented to the Secretary as follows:

- Alabama: "All activities in the area of offshore Alabama relating to or resulting from Federal OCS Leasing, drilling and production activities proposed for the new 5-year program and under the present 5-year program should be consistent with the laws, rules, and regulations of the State of Alabama. Any exploration or development scenarios in the area of offshore Alabama whether under the new 5-year program or the present 5-year program should be compatible with Alabama's Coastal Zone Management Program policies and consistency certification requirements."

- California: "My review of the Draft Proposed Program has identified several points which do not appear to be in the best interests of California and do not reflect the goals and policies of the state and the local governments in our coastal areas. These points fall within the following general categories stated in my Secretary of Environmental Affairs' letter of September 17, 1984, transmitting my initial comments for the 5-year planning process: (1) the Program should provide alternatives to the current moratoria; (2) sensitive areas should be protected through subarea deletions; (3) onshore impacts should be fully considered, including effects on local plans, air quality, and coastal infrastructure; and (4) adequate participation of local government in the planning process should be ensured through appropriate size and timing of lease sales."

- Connecticut: "Connecticut also continues to support the consistency review for lease sales and their potential impacts upon coastal area management programs."

- Delaware: "Regarding Delaware's laws, goals, and policies recognized in our Coastal Management Program which could affect OCS leasing, exploratory, development, and production activities, there is a potential for conflict with our program, particularly with provisions of our Coastal Zone Act. This law prohibits heavy industrial development and off shore bulk cargo transfer facilities, including pipelines (in certain circumstances) within Delaware's coastal zone."

- North Carolina: "North Carolina supports exploration and production of the oil and gas resources of the OCS as long as those activities are conducted in an environmentally sound and responsible manner. We insist on this approach as a means of protecting our tourism and recreational interests, our fisheries and cultural resources, and our fragile coastal environment from avoidable environmental impacts."

- Oregon: "I must point out that the kind of general conclusions contained in the social, economic, and environmental sections of the draft proposed five-year schedule would not meet the requirements of the Oregon Coastal Management Program or the Council on Environmental Quality's requirements for completeness of information or worst case analysis."

  "Water - dependent industrial development, particularly manufacturing, which does not jeopardize that natural resources base is being encouraged and planned for through Oregon's local comprehensive planning process. This includes the application of the Ocean Resources Goal 19 with its expressed priority for living natural resources. Consequently, the Department of Interior's ultimate decision regarding the leasing of areas off Oregon must ensure that any oil and gas development be done in a safe and acceptable manner, consistent with Oregon's natural resource conservation and water development values."

- Virginia: "Since the inception of the Middle Atlantic Leasing Program, the Commonwealth of Virginia has been on record as supporting the exploration and development of offshore petroleum resources so long as this is done in a manner consistent with the environmental goals of the Commonwealth. We believe it is essential to protect Virginia's coastal resources, including the Atlantic Ocean off our Coast, Chesapeake Bay and its estuaries, Hampton Roads, Eastern Shore, and Virginia's beaches, wetlands and fisheries."

- Washington: "It is the position of the State of Washington that [OCS related use conflicts] can best be dealt with at the earliest possible stage, i.e., prior to leasing, under the framework of Washington's federally approved coastal zone management (CZM) program."

  "As seismic survey activity increases along the coast in anticipation of leasing, there will be a need to improve coordination between Federal and state permitting procedures. Now that the Washington Department of Ecology has permit authority for seismic surveys in state marine waters, it is appropriate to update the 1982 memorandum of agreement. This can be accomplished via negotiations under the auspices of the Pacific Regional Technical Working Group."

III. Coastal Zone Management

State coastal zone management programs are prepared and approved pursuant to procedures and standards established by the Federal Coastal Zone Management Act (CZMA). Individual State programs vary in several respects. Some States have passed comprehensive State coastal management laws and their programs are based on license, permit, or certification procedures pursuant to these laws. A larger number of States simply have relied on previously existing authorities; a system generally identified as networking. Executive Orders issued by the Governors or a series of interagency agreements are often used to define specific networking requirements.

State programs are most commonly administered through specially created coastal commissions or by chief executive officers of some State department or agency designated as responsible for program implementation. Some States implement most program authorities at the State level while other States allocate substantial authority to local governments with some limitations and oversight requirements reserved to the States.

Section 18 of the Outer Continental Shelf Lands Act (OCSLA) establishes the basic standards and procedures for preparation of the 5-year oil and gas leasing program. Several subparts of this section require consideration of coastal resources and coastal zone management (CZM) programs as part of this process.

- Section 18(a)(1) requires consideration of "the potential impact of oil and gas exploration on other resource values of the outer Continental Shelf and the marine, coastal, and human environments" (emphasis added).

- Section 18(a)(2)(F) requires consideration of "laws, goals, and policies of affected States which have been specifically identified by the Governors . . . ."

- Section 18(a)(3) requires consideration of the proper balance between the potential for oil and gas discovery and "the potential for adverse impact on the coastal zone" (emphasis added).

- Section 18(f)(5) requires the establishment of regulations and procedures for "consideration of the coastal zone management program being developed or administered by an affected coastal State . . ." (emphasis added).

Applicable laws and implementing Federal regulations for the OCS oil and gas leasing, exploration, and development program are adequate to assure the required consideration of the views of coastal States. These laws and regulations establish a phased decisionmaking process which has been reviewed at several levels of the judicial system and has been fully upheld.

The first basic step in the phased process is development of the 5-year OCS Oil and Gas Leasing Program through three stages. The Draft Proposed Program elicited comments on coastal zone management issues which have been analyzed and considered in developing the Proposed Program. Upon publication of the Proposed Program, affected States will have another opportunity to comment on coastal issues. These comments will be considered by the Secretary in the decision process for the Final Program.

The second basic step in the phased decisionmaking process involves development of plans for the conduct of individual lease sales. Leases sales are conducted in accordance with an established multistage process, an outline of which is presented in Appendix L. The outline provides a brief description of each stage and indicates those stages at which coastal zone management issues are considered. It can be seen that throughout the 2-year presale process, from the Call for Information and Nominations to actual lease issuance, there are several specific opportunities for identifying and resolving such issues.

The third basic step in the overall phased decisionmaking process is the approval of exploration plans. Exploration plans and accompanying environmental reports must be provided to each affected State. If the State has an approved CZM program, the exploration plan must receive a consistency concurrence from the State, pursuant to section 307(c)(3) of the CZMA. This is the earliest stage in the overall process where a sufficient amount of specific information is available for a conclusive consistency test. The Conference Committee report on this provision states that section 307(c)(3)(B) ". . . specifically applies the consistency requirement to the basic steps of the OCS leasing process--namely, the exploration, development, and production plans submitted to the Secretary of the Interior. This provision will satisfy State needs for complete information on a timely basis, about details of the oil industry's offshore plans."

The fourth basic step of the OCS decisionmaking process is the approval of development and production plans (or Development Operations Coordination Documents in the Central and Western Gulf of Mexico planning areas). It is not until after this stage that the most significant oil and gas activities in terms of potential environmental effects take place. Earlier exploration activities have little potential for environmental effects and are short-lived. Developmental and production activities are also the most difficult to predict at the lease sale stage. Again, section 307(c)(3) of the CZMA provides for State concurrence in a certification of consistency before any Federal permits may be granted. Additionally, under section 19 of the OCSLA, Governors of all affected States may submit comments on the size, timing, or location of proposed oil and gas development plans. The Secretary, as already noted, is required to accept these comments if he finds that they provide for a reasonable balance between the national interest and the well-being of the citizens of the affected States.

It is essential to recognize that throughout these steps no OCS oil and gas operations capable of affecting coastal resources may be approved unless they: (a) are found to be consistent by the State; (b) are conclusively presumed to be consistent because the State has not dissented within 6 months of submission of an OCS plan; or (c) are found by the Secretary of Commerce to meet a test related to objectives and purposes of the CZMA and/or national security objectives.

Despite the wide variations in coastal program authorities and implementation systems, State coastal programs tend to be very much alike in how they interact with the OCS program. States have direct authority over air, water, and land uses within State territorial waters and adjacent uplands defined as being part of the coastal zone. Pursuant to coastal program authorities, States control site approvals and operating standards for coastally sited OCS offshore support and production delivery and processing facilities. States do not have any direct jurisdiction or authority, however, over operations on the OCS. Under the CZMA, States do have authority, as noted above, to review OCS exploration

plans and development and production plans. No license or permit for any activity described in detail in such plans may receive Federal approval unless States confirm a certification of consistency with State coastal policies or consistency is conclusively presumed upon failure by the State to meet certain standards for timely consistency review. An adverse finding by a State also may be appealed to the Secretary of Commerce.

The most common response by the States reviewing the Draft Proposed Program with respect to CZM issues has been specific mention of the authority to review the consistency of exploration and development and production plans. States which have specifically emphasized consistency review in their comments include Delaware, Alabama, Oregon, Connecticut, Washington, and California. Perhaps there have not been more specific comments from the States because the general scheduling issues of the 5-year program are not clearly related to the specific land and water use guidelines and policies of CZM programs. The States are also fully aware of the future opportunities for consultation in the phased decision process already described. The comments of the State of Oregon are perhaps most relevant in this respect. The Oregon comments indicate that ". . . a prudent decisionmaker at this point must be cognizant of the more rigorous decision tests coming down the road, each with its potential for deletion of area for lease. These tests include . . . the Federal Coastal Zone Management Act 'federal consistency' justification for any subsequent exploration and development decisions."

Limited State CZM comments actually is a predictable result given that the authority contained in coastal programs are applicable to very specific land and water uses and potential impacts which do not take place prior to exploration and development and production operations. There are no States with policies which categorically oppose OCS development. This would not be appropriate as the CZMA contains several sections which require the States to consider national interests and energy self-sufficiency policies in program development. The size, timing, and location questions which can be addressed within the general planning area level of analysis at the 5-year program stage of OCS activity are not directly addressed by the more specific land and water use regulatory schemes of the CZM programs. The CZM programs are inherently more directly applicable to the decisions and activities of exploration and development as well as being directly required to apply at these later stages of the OCS process.

IV. Status of State Coastal Zone Management Programs of Affected States

The following list shows the current status of CZM programs of affected States. The new 5-year program Draft Environmental Impact Statement will contain a brief characterization of each of these State CZM plans.

State	Actual or Estimated Federal Approval Date By Fiscal Year (ends 9/30)	Comments and Status
Washington	1976	Approved
Oregon	1977	Approved
California	1978	Approved
Massachusetts	1978	Approved
Rhode Island	1978	Approved
North Carolina	1978	Approved
Maine	1978	Approved
Maryland	1978	Approved
New Jersey (Bay and Ocean Shore Segment)	1978	Approved
Alaska	1979	Approved
Delaware	1979	Approved
Alabama	1979	Approved
South Carolina	1979	Approved
Louisiana	1980	Approved
Mississippi	1980	Approved
Connecticut	1980	Approved
Pennsylvania	1980	Approved
New Jersey (Remaining Section)	1980	Approved
Florida	1981	Approved
New Hampshire (Ocean and Harbor Segment)	1982	Approved
New York	1982	Approved
Virginia	1986	A draft program document is undergoing review by the Office of Ocean and Coastal Resource Management in the National Oceanic and Atmospheric Administration
Georgia		Non-participating
Texas		Non-participating

APPENDIX D

INTEREST OF POTENTIAL OIL AND GAS PRODUCERS

INTEREST OF POTENTIAL OIL AND GAS PRODUCERS

In a March 22, 1985 Federal Register Notice (50 FR 11585), the Minerals Management Service (MMS) requested industry respondents in particular to rank all planning areas of the OCS. The request for new rankings was needed because the planning areas were reconfigured and the number increased to 26 from the 24 planning areas used at the time of the initial Federal Register Notice (49 FR 28332) on July 11, 1984. Companies were requested to submit separate rankings of planning areas based on (1) hydrocarbon potential; and (2) exploration and development interest. Industry was requested to base both rankings on estimates of resources expected to be unleased as of mid-1986.

In order to encourage the frankest response, a Federal Register Notice (50 FR 20140) on May 14, 1985, extended the period of confidentiality for privileged or proprietary data submitted in response to the request for comments on the Draft Proposed Program. Each respondent's ranking, upon request, is being treated as confidential privileged or proprietary data for a period of 5 years after final approval of the new 5-year program. Summaries of rankings prepared by MMS and the names of respondents submitting rankings are not being treated as confidential information.

New rankings were received from 9 companies. Six companies submitted full rankings in both categories of interest and potential. Three companies submitted partial rankings in both categories. Full rankings were submitted by Amoco, Shell, Chevron, Exxon, Mobil, and Sohio. Tenneco, BP Alaska, and Union Texas Petroleum submitted partial rankings. Table D-1 shows the overall ranking and the range of companies' rankings with respect to interest in OCS planning areas.

The small number of responses received limits the use of aggregate rankings to only a rough, general guide to industry interest in particular planning areas. Furthermore, any method used to provide an overall indication of industry interest and potential results in some distortion of information, especially since all respondents did not submit rankings for all planning areas. Also not all companies have the same information base, investment strategy, and experience. Table D-2 shows the rank order of planning areas based on MMS's risked estimates of unleased undiscovered economically leasable resources and industry rankings of planning areas by interest and potential using three different averaging techniques.

Each set of industry rankings in Table D-2 is based on a different method for calculating the mean of the submitted rankings. While it is possible to use several measures of central tendency to compare the relative rankings of planning areas as submitted, the small sample of data in this case suggests that using the mean of the individual rankings to compile an aggregate composite ranking may provide the most meaningful analysis of the results.

Difficulty arises over the question of the treatment of areas that have not been ranked by all companies. To use only rankings that include all 26 planning areas in the analysis reduces some bias in the method of assessing the individual position of any given planning area in the rank order. Such a technique, however, would ignore the judgements of companies submitting only partial rankings and would reduce an already small pool of information. The fact that an area has not been included among others in the ranking scheme submitted by a particular respondent indicates little about where it would have been ranked had it been included.

Table D-1

Industry Interest in OCS Planning Areas

Based on the March 1985 Request

(Not all companies ranked all areas)

Overall Ranking/1		Range of Companies' Rankings/2
1	Central Gulf of Mexico	1 to 2
2	Western Gulf of Mexico	2 to 5
3	Beaufort Sea	1 to 6
4	Southern California	1 to 8
5	Eastern Gulf of Mexico	3 to 10
6	North Aleutian Basin	3 to 9
7	Central California	4 to 11
8	Navarin Basin	4 to 10
9	Northern California	4 to 11
10	Chukchi Sea	4 to 20
11	St. George Basin	8 to 17
12	Norton Basin	9 to 18
13	Hope Basin	9 to 19
14	North Atlantic	12 to 17
15	Mid-Atlantic	11 to 21
16	Cook Inlet	10 to 21
17	South Atlantic	12 to 22
18	Washington-Oregon	11 to 22
19	Straits of Florida	14 to 24
20	Gulf of Alaska	15 to 22
21	Shumagin	14 to 25
22	Kodiak	18 to 25
23	St. Matthew-Hall /3	16 to 26
24	Aleutian Basin /3	14 to 25
25	Bowers Basin /3	21 to 26
26	Aleutian Arc /3	20 to 26

/1 Rank order of mean (average) ranks of companies ranking the OCS planning area on the basis of interest in exploration and development.

/2 Reflects highest and lowest ranking by companies ranking the particular OCS planning area on the basis of interest in exploration and development.

/3 These four areas were deleted from the Draft Proposed 5-Year Program.

Table D-2 - MMS/INDUSTRY RANKINGS OF PLANNING AREAS FOR THE PROPOSED 5-YEAR PROGRAM /1

Planning Area/2	Rank Order by MMS Risked Estimates of Unleased Undiscovered Economically Leasable Resources in Millions of BOE (as of Jan. 1987)/3	Rank Order for All Companies Ranking Planning Area Interest/Potential (as of Mid-1986)	Rank Order for Adjusted Company Rankings Interest/Potential (as of Mid-1986)/4	Rank Order for Adjusted Company Rankings Interest/Potential (as of Mid-1986)/5
Central Gulf Mexico	1 (4,603-4,662)	1/2	1/2	1/2
Western Gulf of Mexico	2 (4,491-4,630)	2/3	2/3	2/3
Southern California	3 (1,046-1,264)	4/4	4/4	4/4
Navarin Basin	4 (178-785)	8/5	8/5	6/5
South Atlantic	5 (392-730)	17/15	17/15	17/15
Eastern Gulf of Mexico	6 (331-470)	5/7	7/8	9/8
Northern California	7 (281-414)	9/10	9/10	7/10
Central California	8 (320-405)	7/9	6/9	8/9
Beaufort Sea /6	9 (*-308)	3/1	3/1	3/1
Mid-Atlantic	10 (88-184)	15/14	15/13 (tie)	14/12
St. George Basin	11 (*-160)	11/11	11/11	11/11
Washington-Oregon	12 (46-56)	18/18	18/18	18/18
North Atlantic	13 (35-74)	14/12	14/12	15/13
Straits of Florida	14 (6-6)	19/20	21/20	21/20
Chukchi Sea /6	15 (*-400)	10/6	10/6	10/6
Gulf of Alaska	16 (*-28)	20/19	19/19	19/19
North Aleutian Basin	17 (*-16)	6/8	5/7	5/7

Table D-2 (continued) - MMS/INDUSTRY RANKINGS OF PLANNING AREAS FOR THE PROPOSED 5-YEAR PROGRAM /1

Planning Area/2	Rank Order of MMS Risked Estimates of Unleased Undiscovered Economically Leasable Resources in Millions of BOE (as of Jan. 1987)/3	Rank Order for All Companies Ranking Planning Area Interest/Potential (as of Mid-1986)	Rank Order for Adjusted Company Rankings Interest/Potential (as of Mid-1986)/4	Rank Order for Adjusted Company Rankings Interest/Potential (as of Mid-1986)/5
Norton Basin	18 (*-12)	12/16	(tie) 12/16	12/16
Kodiak	*	22/23	22/22	22/22
Hope Basin	*	13/13	(tie) 12/13 (tie)	13/14
Shumagin	*	21/24	20/24	20/23 (tie)
Cook Inlet	*	16/17	16/17	16/17
Aleutian Basin /7	*	24/22	24/23	24/23 (tie)
Bowers Basin /7	*	25/25	25/25	25/25
St. Matthew-Hall /7	*	23/21	23/21	23/21
Aleutian Arc /7	*	26/26	26/26	26/26

/1 Industry rankings were made in Spring 1985 by companies estimating interest and potential effective mid-1986.

/2 Planning areas are ordered by "Leasable Resources" assuming a $24 per barrel 1985 starting price (see Appendix F).

/3 The range of "Leasable Resources" is based on assumptions from $19 to $29 per barrel 1985 starting prices. The stub of the table is rank ordered by leasable resources based on the assumption of $24 per barrel 1985 starting price (see Appendix F).

/4 Any area not ranked by a company was adjusted by assigning the area the highest value not assigned by the company submitting the rankings.

/5 Any area not ranked by a company was adjusted by assigning the area the middle value among the unassigned values submitted by the company.

/6 Calculations exclude Beaufort Sea and Chukchi Sea natural gas (see Appendix F).

/7 These four areas were deleted from the Draft Proposed 5-Year Program.

* Negligible (estimated to be less than 0.5 million BOE). The eight lowest ranked planning areas have been assigned no rank order because their resource magnitudes are estimated to be negligible.

To overcome the difficulty of dealing with unranked areas, values can be assigned in several ways to indicate implied rankings. If values are assigned, a comparison of rankings by all respondents can be made without adjusting the number of cases within each rank when calculating the mean value for unranked planning areas. Two suggested ways of handling such implied rankings are:

- to assign each unranked area the highest rank not assigned by a company (i.e. 11 if the company ranked only 10 areas, 16 if the company ranked 15 areas, and so on); and

- to assign each unranked area a middle value among the unassigned values submitted by the particular respondent (i.e. 18 in the case of areas not ranked by a company listing only 10 areas--18 is the mid-point between 10 and 26).

Each of these two methods for developing a ranking scheme can result in some form of distortion. Such distortion notwithstanding, either method provides an opportunity to compare the rankings of all respondents without ignoring the input of respondents who submitted only partial rankings and without further reducing the already small number of cases to be included in the analysis.

The first set of industry rankings (Column 3) on Table D-2 is based on the calculation of individual arithmetic means for each of the 26 planning areas. Calculation of the arithmetic mean for each of the rank orders is based on the number of respondents (n) ranking each particular planning area. No values were assigned to unranked areas.

The second set of industry rankings (Column 4) is also based on the calculation of an arithmetic mean for each of the 26 planning areas. The mean for each of the planning areas was calculated using an n of 9 cases. Unranked planning areas were assigned the highest rank order not assigned by the respondent submitting the rankings.

The third set of industry rankings (Column 5) was compiled and calculated using the same procedure as that used to compile the rankings in Column 3 except that unranked planning areas were assigned the middle value (rank order) among the unassigned values submitted by the particular respondent. Within the ranking schemes, the rank order values to compile both industry interest and potential were handled using the same technique.

The Draft Proposed Program included a table of rankings showing industry interest in OCS planning areas based on comments received in response to the July 1984 Federal Register Notice. Table D-3 shows the earlier rankings of industry interest.

Rankings received in response to the March 1985 Federal Register Notice may provide a more reliable indication of industry interest for the Proposed Program and attention should focus on them rather than on the earlier rankings. Several reasons for this are apparent. After the earlier request for rankings, planning areas were increased in number from 24 to 26, and planning area boundaries off California and in the South Atlantic were reconfigured. Responses to the March 1985 request for rankings were submitted by fewer but larger companies, thereby altering the composition of the rankings. To combine or closely compare the two sets of rankings could result in misleading information.

Table D-3

Industry Interest in OCS Planning Areas

Based on the July 1984 Request /1

(Not all companies ranked all areas.)

Overall Ranking /2	Range of Companies' Rankings /3
1 Central Gulf of Mexico	1 to 5
2 Western Gulf of Mexico	1 to 7
3 Beaufort Sea	1 to 7
4 (tie) Southern California	1 to 11
4 (tie) Central & Northern California	3 to 14
6 Eastern Gulf of Mexico	3 to 12
7 Navarin Basin	2 to 11
8 North Aleutian Basin	3 to 14
9 St. George Basin	3 to 15
10 Chukchi Sea	2 to 13
11 North Atlantic	7 to 22
12 Norton Basin	8 to 18
13 Washington-Oregon	5 to 21
14 Mid-Atlantic	9 to 23
15 Hope Basin	10 to 19
16 Cook Inlet	9 to 20
17 Shumagin	12 to 22
18 South Atlantic	10 to 24
19 Gulf of Alaska	12 to 21
20 St. Matthew-Hall	14 to 23
21 Kodiak	13 to 24
22 Bowers Basin	16 to 24
23 (tie) Aleutian Arc	12 to 24
23 (tie) Aleutian Basin	15 to 23

/1 This table is included for historic purposes. See cautionary note in the last two paragraphs of p. D-5.

/2 Rank order of mean (average) ranks of companies ranking the OCS planning area on the basis of interest in exploration and development.

/3 Reflects highest and lowest ranking by companies ranking the particular OCS planning area on the basis of interest in exploration and development.

APPENDIX E

GEOLOGICAL AND GEOPHYSICAL DATA

GEOLOGICAL AND GEOPHYSICAL DATA

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I. Geologic & Geophysical Data

A brief synopsis of the seismic, continental offshore stratigraphic test (COST) well and exploratory well data available in each planning area is presented below. The figures given for seismic data indicate the amount of such data acquired by the Minerals Management Service (MMS) as of the end of Fiscal Year 1984. These figures differ significantly from those in Appendix E of the Draft Proposed Program, which reported the total amount of data collected by industry.

The Navarin Basin Planning Area

Seismic surveying activity by government and academic institutions has been ongoing since the mid-1960's. These surveys have been mostly reconnaissance mapping efforts investigating the regional geologic framework. Industry-related seismic activity has been ongoing since 1971. A total of 57,000 line miles of common-depth-point (CDP) seismic reflection data have been acquired by the MMS. ARCO Alaska, Inc., drilled a COST well in the summer of 1983, and 3 exploratory wells have been drilled as of September 1, 1985.

Hope Basin Planning Area

Two State stratigraphic test wells, the Niniuk Point No. 1 and the Cape Espenberg No. 1 wells, were drilled north and south of the entrance to Kotzebue Sound just east of the planning area in 1974 and 1975 by Standard Oil of California. Seismic exploration in the area began in 1972. The MMS has acquired 4,500 line-miles of CDP seismic surveys collected by industry and supplemented by U.S. Geological Survey (USGS) regional seismic data.

Beaufort Sea Planning Area

Industry began acquiring CDP seismic data in Federal waters in 1964, and 26,000 line-miles shot primarily over the continental shelf have been acquired by the MMS. Nine exploratory wells have been completed on Federal acreage as of September 1, 1985.

Kodiak Planning Area

A total of 13,000 line-miles of seismic data shot across Kodiak shelf have been acquired. Several stratigraphic test wells have been drilled on Kodiak shelf. The first three, which were drilled in 1976, KSST 1, 2, and 3, reached total depths of 4,225 feet, 4,337 feet, and 1391 feet respectively. The remaining three wells, KSSD 1,2, and 3, were drilled the following year and reached total depths of 8,514 feet, 10,452 feet, and 9,355 feet, respectively. In addition, in 1971, the Deep Sea Drilling Project (DSDP) drilled two holes on the continental slope off Kodiak Island.

Norton Basin Planning Area

Seismic reflection surveying by government and academic institutions has been ongoing since the mid-1960's. These surveys have been mostly reconnaissance mapping efforts investigating the regional geologic framework. Industry has been surveying Norton Sound since 1971 in order to establish a high density seismic grid covering the prospective areas of the basin. A total of 22,000 line-miles of CDP seismic data have been acquired by the MMS. ARCO Alaska, Inc., drilled two COST wells in the planning area during the summers of 1980 and 1982. Six exploratory wells have been drilled as of September 1, 1985.

Chukchi Sea Planning Area

The first exploration permit for the Chukchi Sea planning area was issued in 1969. The MMS has acquired approximately 27,000 line-miles of CDP seismic data. No COST wells have been drilled.

St. George Basin Planning Area

Seismic exploration in St. George Basin has been occurring since 1970, and more than 29,000 line-miles of seismic data have been acquired. The basin is in the early stage of exploratory drilling. Two COST wells and nine exploratory wells have been completed as of September 1, 1985.

Shumagin Planning Area

The Shumagin planning area is a frontier region without well data. A geophysical grid pattern of 24-and 48-fold CDP data shot from 1974 to the present within the Shumagin planning area, along with geologic and geophysical data on the adjacent Kodiak shelf, is the basis for understanding the resource potential for the Shumagin planning area. The MMS has acquired 3,000 line-miles of CDP seismic data.

Gulf of Alaska Planning Area

Permits for seismic acquisition in the Gulf of Alaska were first issued in 1962. A total of 49,000 line-miles of CDP seismic data have been acquired. Twelve exploratory wells and one COST well have been drilled since 1977 without discovery of an oil or gas reservoir as of September 1, 1985.

Cook Inlet Planning Area

Permits to collect seismic data in the Cook Inlet area were first issued in 1964. The MMS has acquired 17,000 line-miles of CDP seismic data. One COST well and thirteen exploratory wells have been drilled as of September 1, 1985.

North Aleutian Basin Planning Area

Collection of geophysical data in the North Aleutian Basin began in 1963. The MMS has acquired 29,000 line-miles of CDP seismic data. One COST well was completed in January 1983. Nine exploratory wells have been drilled on the Alaska Peninsula adjacent to the axis of Bristol Bay as of September 1, 1985.

North Atlantic Planning Area

The MMS has acquired approximately 68,000 line-miles of CDP seismic data in the North Atlantic planning area. Two COST wells, completed in 1976 and 1977, and eight exploratory wells have been drilled as of September 1, 1985.

Mid-Atlantic Planning Area

The MMS has acquired approximately 53,000 line-miles of CDP seismic data in the Mid-Atlantic planning area. Two COST wells, completed in 1976 and 1979, and 32 exploratory wells have been drilled as of September 1, 1985.

South Atlantic Planning Area

The MMS has acquired approximately 57,000 line-miles of CDP seismic data in the South Atlantic planning area. One COST well, completed in 1977, and six exploratory wells have been drilled as of September 1, 1985.

Straits of Florida Planning Area

The MMS has acquired about 2,000 line-miles of CDP seismic data in the Straits of Florida planning area. Fourteen exploratory wells have been drilled in the Florida Keys area as of September 1, 1985.

Eastern Gulf of Mexico Planning Area

Approximately 66,000 line miles of seismic data have been acquired by the MMS in this planning area. A total of 27 exploratory wells and one development well have been drilled as of May 1, 1985.

Central Gulf of Mexico Planning Area

Approximately 133,000 line miles of seismic data have been acquired by the MMS in this planning area. A total of 5,532 exploratory wells and 14,454 development wells have been drilled as of May 1, 1985.

Western Gulf of Mexico Planning Area

Approximately 124,000 line miles of seismic data have been acquired by the MMS in this planning area. Two COST wells, 1,446 exploratory wells, and 1,476 development wells have been drilled as of May 1, 1985.

Southern California Planning Area

The MMS has acquired approximately 60,000 line-miles of seismic data in this planning area. Two COST wells have been completed: one in 1975 and another in 1976. A total of 273 exploratory wells have been drilled as of December 31, 1984.

Central California Planning Area

The MMS has acquired approximately 19,000 line-miles of seismic data in this planning area. Twelve exploratory wells were drilled from 1964 to 1967.

Northern California

The MMS has acquired approximately 11,000 line-miles of seismic data in this planning area. Seven exploratory wells were drilled from 1964 to 1966.

Washington-Oregon Planning Area

The MMS has acquired approximately 3,000 line-miles of seismic data in this planning area. Twelve exploratory wells were drilled from 1965 to 1967.

II. Grid Coverage/Quality of Geological and Geophysical Data for Regional Resource Estimates /1

Area	Coverage/Quality
Atlantic	
North	Good
Mid	Good
South	Poor to Fair
Straits of Florida	Very Poor
Alaska	
Beaufort Sea	Fair to Good
Chukchi Sea	Poor
Hope Basin	Fair
Norton Basin	Fair to Good
Navarin Basin	Fair to Good
St. George Basin	Good
North Aleutian Basin	Good
Kodiak	Good
Cook Inlet	Good
Gulf of Alaska	Fair to Good
Shumagin	Very Poor
Gulf of Mexico	
Central	Excellent
Western	Excellent
Eastern	Good
Pacific	
Northern California	Poor to Good
Central California	Poor to Good
Southern California	Fair to Excellent
Washington-Oregon	Poor

/1 Supplied by MMS regional offices based upon quantity and quality of data currently available.

III. Value of Additional Data

The value of additional geological and reservoir engineering data in a particular area is dependent upon: a) the geology of the area, b) the existing data base, and c) the extent to which the new information and data conform to the previous interpretations.

In the simplest case, a frontier OCS area (including some deepwater portions of the GOM) with little or no existing empirical geological and reservoir engineering data, extrapolation of geologic data from onshore and bottom samples, and comparison to analog basins/areas is necessary. Exploration of these areas generally involves high geologic and economic risk. Early exploration focuses on large easily identifiable structural targets. More than 75 percent of the world's giant (500 MMBO or larger) oil fields are found in structural traps. In this type of area the value of new information is tremendous. If it tends to confirm a particular interpretation, it is valuable because it reduces uncertainties (it may in fact invalidate previous interpretations, also reducing uncertainty). If the new information does not confirm previous interpretations, it is valuable because it results in new interpretations that may lead to additional exploration and with that, additional information.

In an intermediate case, a moderately explored area with existing production, additional information is generally less valuable. In this case both the larger and the less risky structures have been explored. Exploration shifts to smaller, more subtle prospects. In this type of area, empirical geological and reservoir engineering data are available. It is much more difficult for the information obtained from an additional well to influence interpretations and exploration strategies covering large areas or entire basins.

On the other end of the spectrum are mature producing areas such as the shallow water GOM shelf. Extensive geological and reservoir engineering data exist. Only the smallest and subtlest traps remain to be explored. In these areas it is extremely unlikely (almost impossible) for the information obtained from an additional well to have any regional influences because of the abundance of existing information. The value of this information is generally to reduce uncertainties surrounding that particular prospect--existence of trapping mechanisms and hydrocarbons; the amount of pay and potential reservoir rock, etc. However, information gained from drilling a well to deeper prospects to reevaluate old acreage, a current industry trend, could be extremely important in indicating regional sand distribution and geology.

APPENDIX F

ECONOMIC CONSIDERATIONS IN THE 5-YEAR OUTER CONTINENTAL SHELF LEASING PROGRAM

ECONOMIC CONSIDERATIONS IN THE 5-YEAR
OUTER CONTINENTAL SHELF LEASING PROGRAM

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ECONOMIC CONSIDERATIONS IN THE 5-YEAR
OUTER CONTINENTAL SHELF OIL AND GAS PROGRAM

I. Introduction

This appendix discusses the economic considerations that are important in the formulation of a 5-year OCS oil and gas leasing program. It also describes the methods used to estimate the economic benefits of leasing and gives the resulting estimates for the various planning areas of the OCS.

Past practice and court rulings have established the qualitative and quantitative analysis of the benefits of OCS oil and gas production as an essential part of the considerations required of the Secretary of the Interior in formulating a 5-year leasing program under section 18 of the OCS Lands Act (OCSLA). Thus, in section II the statutory objectives of the OCSLA and the considerations required in formulating a leasing program are discussed and translated into economic terms.

Section III gives a brief history of OCS leasing.

Section IV discusses the relevance and importance of economic considerations in the management of OCS oil and gas resources and explains how the U.S. economy benefits from the production of OCS oil and gas.

In section V, the discussion turns to the economic characteristics of OCS oil and gas resources and the basic economic investment decisions involved in bringing them into production. This discussion yields a general rule for sequencing the development of these resources that would maximize their economic benefits to society which is important to consider in formulating a 5-year leasing program.

Section VI examines the sequencing of oil and gas investment decisions in the private sector. It also presents the resource and economic estimates used in developing the 5-year program.

Section VII describes the computational methods and assumptions used to estimate the geologic and economic measures associated with leasing and investing in each OCS planning area. These estimates provide the basic direct economic criteria which are considered by the Secretary, along with other important factors, in structuring, evaluating, and choosing among alternative leasing schedules for the 5-year program.

II. Statutory Objectives and Economic Benefits

The OCS Lands Act Amendments of 1978 establish specific purposes relating to the development of the oil and natural gas resources of the OCS. Among these purposes are those which can be categorized as economic considerations which are to be taken into account in managing the oil and gas resources.

Section 102(1) requires policies and procedures to be established:

> . . . which are intended to result in expedited exploration and development of the Outer Continental Shelf . . .
>
> in order to achieve national economic and energy policy goals,
>
> assure national security,
>
> reduce dependence on foreign sources, and
>
> maintain a favorable balance of payments in world trade;

Section 102(2) goes on to require the development of the oil and gas resources of the OCS in a manner consistent with the responsibility:

> . . . to make such resources available to meet the Nation's energy needs as rapidly as possible . . .
>
> to balance orderly energy resource development with protection of the human, marine, and coastal environments,
>
> to insure the public a fair and equitable return on the resources . . . and
>
> to preserve and maintain free enterprise competition . . . .

Section 18(a) requires the Secretary to prepare, revise, and maintain a 5-year leasing program consisting of a schedule of lease sales which considers, among other things, economic values of the nonrenewable resources of the OCS.

Development of oil and gas resources should be viewed within the context of the Federal Government's overall national energy policy as expressed in the The National Energy Plan, U.S. Department of Energy, October 1983. Energy policy is approached as one part of an overall economic policy based on less Federal regulation, lower taxes, reduced Federal expenditures, and maximum reliance on the private sector to make decisions about the production and consumption of commodities, including energy. The central goal of the national energy policy is to foster an adequate supply of energy at reasonable costs. Two basic strategies to achieve that goal are to promote a balanced and mixed energy resource system, and to minimize Federal control and involvement in energy markets while maintaining public health and safety, and environmental

quality (The National Energy Policy Plan). Leasing lands on the OCS is one measure which the Federal Government is taking to further exploration and development of domestic energy resources in order to implement these strategies.

The National Energy Policy Plan indicates that offshore leasing of oil and gas should be conducted to achieve the important benefit of timely and efficient energy production. Within the context of the overall economic goal of maximum reliance on the private sector to make decisions about production, the private marketplace is given great weight in determining timeliness and efficiency of OCS oil and gas exploration and development. The Federal Government, on the other hand, plays a major role because of its ownership of the OCS oil and gas resources. The Federal Government aims at the initial structuring of that marketplace in a manner which does not restrict the orderly and timely development of the resource, while assuring the public of a fair return for the rights conveyed. Because oil and gas affects the entire U.S. economy, its development is intricately tied to overall sustained economic growth. The domestic production of oil and gas not only results in the generation of these hydrocarbons and their associated market values, along with the jobs and income created and the contribution of these products to the sustained growth of the industrial, transportation, and residential/commercial sectors; it also has secondary and tertiary linkages to income generation and jobs in other sectors of the economy.

As will be discussed in section IV, the primary benefit of efficient OCS oil and gas development is the availability of oil and gas at a cost to the economy that is less than the market value of the oil and gas produced. To the extent that more OCS oil and gas is produced and costs are less than the market price, the U.S. economy will be more productive overall, yielding a greater total of goods and services valued by American consumers.

The economic benefits of timely and efficient exploration and development of the oil and gas resources of the OCS can be measured quantitatively to determine the potential contribution which these resources might make to the productivity of the U.S. economy. They can be measured in terms of receipts to the U.S. Government in the form of bonuses, rentals, royalties, and taxes, plus the economic profits accruing to industry. They also can be measured equivalently as the net discounted value of the production revenues less the costs of OCS activities. In both cases, the net present value of undiscovered economically recoverable OCS petroleum resources remaining to be offered at the start of the next 5-year program is estimated to be approximately $40 to $90 billion at "current" (January 1987) prices.

III. Brief History of OCS Leasing

Oil production off our shores began in 1896. Approximately 400 shallow wells were drilled from wooden piers extending from the Summerland shoreline, near Santa Barbara, California, in State waters. This was the first time offshore oil was produced in the United States. The first attempt to drill an offshore well in the Gulf of Mexico began in 1933. In October 1937, the first well to produce hydrocarbons from the Gulf of Mexico was drilled off Louisiana; production began in 1938.

Since the enactment of the OCSLA in 1953, the Bureau of Land Management (BLM) and subsequently, since 1982, the Minerals Management Service (MMS) have conducted 81 oil and gas lease sales and offerings. The first general oil and gas Federal lease sale was held for Gulf of Mexico acreage on October 13, 1954. From that time through 1973, 28 additional OCS sales were held, including 9 drainage sales in the Gulf of Mexico and 15 general lease sales (4 of which were in the Pacific). Generally, one or two sales were held annually until 1969. In January 1969, a blowout occurred on a lease in the Santa Barbara Channel. As a result, no lease sales were held in the Gulf of Mexico until 1970 and in the Pacific until 1975.

In response to the OPEC Oil Embargo of 1973-74, goals were set to lease 10 million acres annually between 1974 and 1980 (an amount equal to the acreage leased in the previous 21 years). As a result, the number of lease sales was increased to 12 in the 3-year period from January 1974 through December 1976 (9 in the Gulf of Mexico and 1 each in the Pacific, Alaska, and the Atlantic). In 1977, two sales were held. Beginning with 1978, the number of sales again increased to four in 1978 and six in 1979. Three sales were held in 1980.

In 1978, the OCSLA was amended. Section 18 of the amended act required the Secretary of the Interior to formulate a 5-year plan for OCS leasing, specifying to the maximum extent practicable the size, timing, and location of lease sales. Section 8 required the Secretary to experiment with offering tracts for lease under different bidding systems for a 5-year period which ended in September 1983. In June 1980, Secretary Andrus adopted the first 5-year leasing program for the period 1980-1985. Under this plan, seven sales were held in 1981 and five in 1982. Various state and environmental groups sued Secretary Andrus. In 1981, the U.S. Court of Appeals for the District of Columbia Circuit held that several aspects of the plan did not conform to the requirements of section 18 and directed the Secretary to correct these deficiencies. After additional studies, Secretary Watt approved the second 5-year leasing program in July 1982 which provided for 41 sales over 5 years and extended the plan through mid-1987. This program was designed primarily to increase the quality, pace, and acreage of offerings to achieve early leasing of high potential areas. The first areawide sale was held in the Mid-Atlantic in April 1983, and the following month the first areawide sale was held in the Central Gulf of Mexico. The results of this latter offering set a new record high for the 30-year leasing program based upon the amount of bonus bids offered, high bids, and bids accepted.

In the 29 1/2-year history of Federal offshore leasing before areawide offerings (1954 through April 25, 1983):

- 64 million acres of the OCS were offered for lease;
- 27.3 million acres received bids;
- 24 million acres were leased:
  - 16 million acres or 3,559 tracts were leased in 47 sales in the Gulf of Mexico,
  - 2.8 million acres or 512 tracts were leased in 10 sales offshore Alaska,
  - 2.1 million acres or 362 tracts were leased in 8 sales in the Atlantic,
  - 2.4 million acres or 439 tracts were leased in 9 sales in the Pacific. Of the Pacific acreage, 0.4 million acres were in southern California, including the Santa Barbara Channel.

In contrast, since the beginning of areawide leasing on April 26, 1983:

- 268 million acres of the OCS were offered for lease through April 1985.
- 14.1 million acres received bids
- 13.0 million acres were leased:
  - 10.4 million acres or 1,999 tracts were sold in 5 sales in the Gulf of Mexico,
  - 2.2 million acres or 407 tracts were sold in 2 sales offshore Alaska,
  - 0.3 million acres or 48 tracts were sold in 2 sales in the Atlantic,
  - 0.2 million acres or 31 tracts were sold in 2 sales in the Pacific.

A total of 4,970 leases were in effect as of March 1, 1985; this included 3,854 leases in the Gulf of Mexico, 151 in the Atlantic, 183 offshore California, and 714 offshore Alaska.

As of March 1, 1985, 1,242 leases were producing. Of the total producing leases, 1,204 were in the Gulf of Mexico and 38 were offshore California. The remaining 3,728 leases were nonproducing. OCS revenues (bonuses, rentals, and royalties) received totaled more than $76 billion for the period from 1954 through 1984.

The scope and emphasis of the July 1982 5-year plan was a significant change from the past programs that generated leasing of about 3 percent of the OCS in 29-1/2 years. It is predicted that 85 percent of America's untapped oil wealth is on publicly owned lands, two-thirds of which are offshore. The current plan provides access to the most promising offshore areas, allows companies to determine the focus of their exploration efforts, and encourages the flexibility needed to test diverse exploration strategies which could result in major new finds benefiting the nation as a whole.

IV. The Relevance and Importance of Economic Considerations

A. Introduction

OCS oil and gas resources represent both a current and potential future domestic energy source to our nation. This section presents a broad overview of the role of energy and, more specifically, oil and gas in our national economy. It presents a general framework of our current and projected domestic production and reserve status of domestic hydrocarbons. In addition, it summarizes our import situation from the 1970's to the present which reflects a combination of Government policies and market influences which have substantially decreased our vulnerability to supply disruptions such as we have experienced in the past. It also addresses what the import picture is likely to be in the future and the implications which this has for our national security and our national economy. This section also discusses the role which OCS oil and gas resources can play in future domestic energy production and the factors which influence their development. Finally, it discusses the way in which OCS oil and gas resources contribute to the productivity of the U.S. economy and the effect of offshore exploration and development costs on the resulting economic benefits.

B. Role of Oil and Gas in Our National Economy

1. Energy in General

The role of energy in the maintenance and growth of our industrial economy has been a critical one from its infancy to the present. In 1984, the United States consumed 73.7 quadrillion (quad) British thermal units (Btu) of energy (U.S. Department of Energy, Annual Energy Review, April 1985). Of that total, oil and gas constituted 66.6 percent of our domestic consumption of energy, coal represented 23.3 percent, and the remaining 10.1 percent was hydroelectric, nuclear, geothermal, wood, waste, and wind energy. Table 1 presents a breakdown of 1984 U.S. energy consumption by source.

Total energy consumption by the three major end-use sectors increased during 1984. The industrial sector consumed 37.8 precent of the total, the residential and commercial sector consumed 35.2 percent, and the transportation sector consumed 26.9 percent of the total (Ibid.).

The international events of the 1970's, highlighted by the OPEC oil embargo of 1973, resulted in significant changes in the use of energy within the U.S. economy. The dramatic increase in the price of oil on the world market (from October 1973 to January 1974, the price quadrupled) resulted in energy use efficiency and conservation measures in the United States, unparalleled in our history. Energy efficient home-heating devices and the switch to more fuel-efficient cars began during this period, reflecting the American consumers' reaction to increased prices.

Table 1

U.S. 1984 Consumption of Energy by Source

	Quadrillion Btu[1/]
Petroleum	31.00
Natural Gas (dry)	18.03
Coal	17.20
Hydroelectric Power	3.78
Nuclear Electric Power	3.55
Net Imports of Coal Coke	(0.01)
Other[2/]	0.17
TOTAL ENERGY CONSUMED[3/]	73.73

1/ 1 Quadrillion Btu/year = 0.4724 MMBD (million barrels per day) of domestic oil
= 0.4696 MMBD of imported oil
= 2.649 billion cubic feet of natural gas/day

2/ Includes electricity produced from geothermal wood, waste, wind, photovoltaic, and solar thermal sources connected to electric utility distribution systems.

3/ Total does not equal sum of components due to independent rounding.

Source: U.S. Department of Energy, Energy Information Administration (DOE/EIA), Annual Energy Review 1984, April 1985, p.5.

One measure which reflects the more efficient use of energy in the economy is the amount of energy consumed per dollar of Gross National Product (GNP). In the period from 1950 to 1973, energy consumed per dollar of this measure of economic output remained fairly stable as both the amount of energy consumed and the GNP increased at about 3.8 percent per year (U.S. Department of Energy, Energy Projections to the Year 2010, October 1983, p. 10). In response to the energy price increase of the 1970's, energy consumed per dollar of GNP declined by about 18 percent in the period 1974 to 1982 (Ibid.)

The U.S. Department of Energy projects that this energy efficiency trend will continue; between 1982 and 2000, the quantity of energy consumed is projected to increase at 1.3 percent per year, less than half the 2.8 percent annual rate of projected growth in U.S. GNP (Ibid.). Despite the significance of energy efficiency in future energy projections relative to overall economic growth projections, energy consumption in the United States is projected to increase in absolute terms from 73.3 quad Btu (1982) to 93.4 quad Btu (2000), an increase of 27 percent. These consumption needs are projected to be met by indigenous production of energy and imports, with net oil imports projected to account for 12 percent of total U.S. energy consumed (Ibid.).1/

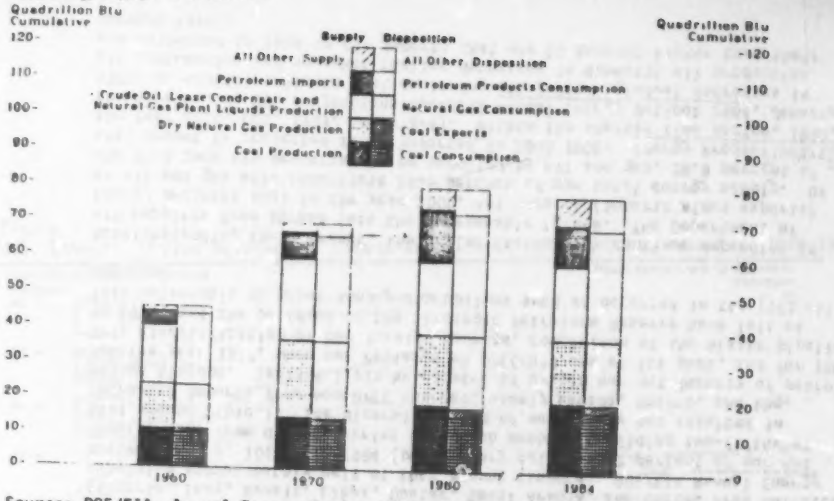
2. Oil and Gas

Relative to the United States supply of energy from other sources, a substantial percentage of our oil and gas (more specifically, oil) supply is imported. Figures 1 and 2 graphically illustrate the role of imports, and more specifically petroleum, in our total supply of energy and its disposition (primarily consumption and exports). In the 1970 to 1980 timeframe, domestic oil and gas production represented approximately 50 to 60 percent of the total energy supplied to the U.S. economy; imports of oil and gas supplied approximately 11 to 18.5 percent (see Table 2). U.S. Department of Energy projections to the year 2000 indicate that imported oil and gas will supply an estimated 14.6 percent of our total domestic energy in the year 2000. (Imported gas constitutes only 3 percent of the 14.6 percent.) Although this percentage has decreased from a high of 18.5 percent in 1975 and 1980, in absolute terms, imports are projected to increase to 13.4 quad Btu in 1990 (a level which they were at in 1975) and to 13.6 quad Btu in the year 2000. Domestic production of oil is projected to decrease from 20.1 quad Btu to 17.4 quad Btu in the same timeframe.

Domestically, the nation's production of oil and natural gas liquids peaked in 1970 and dry natural gas production peaked in 1973, reflecting depletion of older fields without discovery of new reserves sufficient to replace the oil produced. The decline was cushioned by production from the giant Prudhoe Bay oil field. If it were not for production from that field, U.S. production would have plummeted nearly 30 percent over the past decade instead of only 5 percent.

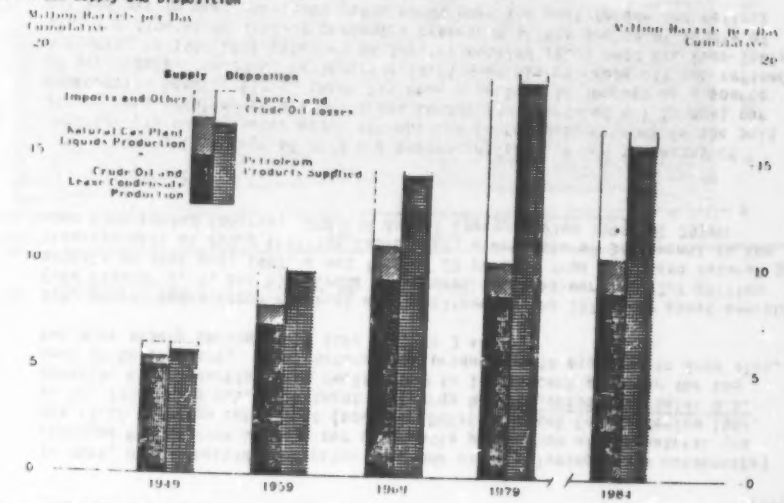
1/These U.S. Department of Energy projections are based on their "Scenario B" assumptions, namely, the world price of oil in 1982 $/bbl of $26 in 1985, $32 in 1990, $57 in 2000, and $84 in 2010; economic growth projections for the period 1982-2000 are assumed to be 2.8 percent annually for the U.S. and 3.0 percent for the free world.

Figure 1
U.S. Energy Supply and Disposition



Source: DOE/EIA. Annual Energy Review 1984. Published April 1985, p. 4.

Figure 2
U.S. Petroleum Supply and Disposition



Source: DOE/EIA. Annual Energy Review 1984. Published April 1985, p. 88.

Table 2

Oil and Gas Energy Supplied to the U.S. Economy

	Total Energy Supplied to U.S. Economy *Quad Btu	Indigenous Production Oil *Quad Btu	Indigenous Production Gas *Quad Btu	Indigenous Oil and Gas as Percentage of Total Energy Supplied	Net Imports Oil *Quad BTU	Net Imports Gas *Quad BTU	Imported Oil & Gas as Percentage of Total Energy Supplied
1970	68.3	22.9	21.7	65.3	6.9	0.8	11.3
1975	72.4	20.1	19.6	54.8	12.5	0.9	18.5
1980	78.5	20.5	19.9	51.5	13.5	1.0	18.5
Projection							
199C	86.2	19.0	18.2	43.2	12.4	1.0	16.5
2000	93.4	17.4	16.3	36.1	11.0	2.6	14.6

* 1 Quadrillion Btu/year = 0.4724 MMBD (million barrels per day) of domestic oil
= 0.4696 MMBD of imported oil
= 2.649 billion cubic feet of natural gas/day

Source: U.S. Department of Energy: Energy Projections to the Year 2010, October 1983. Table 3-4 "Scenario B--Primary Energy Supplied to the U.S. Economy."

In 1984, U.S. domestic production of crude oil (including lease condensate) averaged 8.8 million barrels per day, while production of dry natural gas was 17.22 trillion cubic feet (source: DOE/EIA Annual Energy Review 1984, p. 85, 133). The U.S. Department of Energy has projected that total U.S. domestic oil production will decline 1.0 to 1.5 percent per year for the next 10 to 15 years. Total natural gas production is expected to drop also, but more slowly through 1990 (see Figures 3 and 4).

U.S. proven hydrocarbon reserves also declined in the 1970's by about one-third (see Figures 3, 4, and 5). Crude oil proved reserves were at 27.7 billion barrels at year end, 1983, a net loss of 29 percent from 1970, and natural gas reserves were at 200.2 trillion cubic feet, a net loss of 31 percent in the same time period (source: DOE/EIA Annual Energy Review 1984, p. 79).

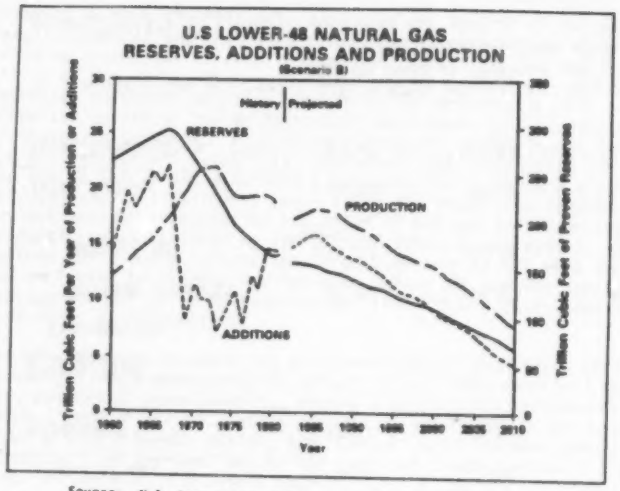
3. Imports

The oil embargo of 1973 and subsequent sharp price increases of imported oil which caused major disruptions in the U.S. economy in the past decade have resulted in a significant change in imports of oil to meet our consumption needs. First, there has been a decline in imports as a source of our supply. In 1980, we imported 14.65 quad Btu of crude oil and refined products; in 1984 this category of imports equaled 11.35 quad Btu (see Table 3). The figures in Table 3 present a breakdown of the source of supply of oil and gas to meet our consumption needs over the past decade and reflect this decline in the overall role of imports.

In addition to the absolute and relative decline of imports, diversification of our supply by country of origin has also occurred. In 1977, 72.3 percent of our net imports of petroleum came from OPEC countries with the Arab members (Algeria, Iraq, Kuwait, Libya, Qatar, Saudi Arabia, and United Arab Emirates) supplying approximately half of that amount (source: DOE/EIA Annual Energy Review 1984, p. 101). In 1984 (preliminary data), 43.2 percent of our net imports came from OPEC countries with Arab members providing two-fifths of that amount (Ibid.). The diversification of our supply has resulted in increased imports from non-OPEC sources, namely Canada, Mexico, and the United Kingdom. Table 4 lists by country of origin our net imports of petroleum for the year 1977, when our reliance on OPEC oil was at its peak, and for 1984. This diversification of our foreign sources, completion of the Alaska pipeline in 1978, and the build-up of the Strategic Petroleum Reserve have left us less vulnerable to major supply disruptions such as occurred in the 1973 oil embargo.

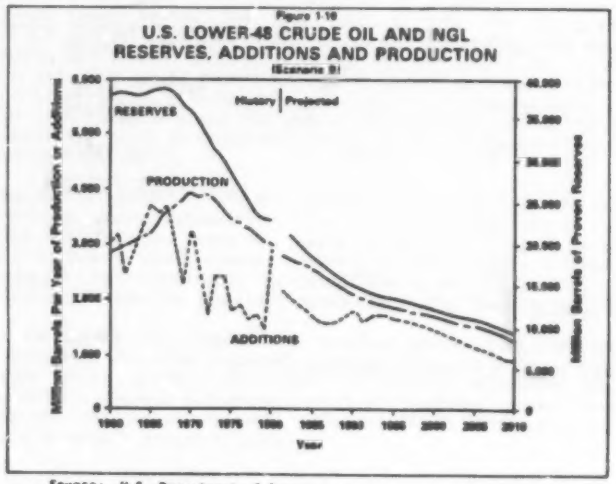
Notwithstanding these trends, the United States will continue depending on oil supplies from abroad into the foreseeable future. The Department of Energy projects that in the year 2000, net imports (imports minus exports) of oil and gas will constitute 14.6 percent of our total energy supply. Of the 47.3 quad Btu projected to be supplied by oil and gas, 28.8 percent of that amount is projected to be imported in 2000 (DOE: Energy Projections to the Year 2010, Oct. 1983, Table 3-4). Within the shorter time period, 1990, the most recent DOE projections (DOE/EIA Annual Energy Outlook 1984, January 1985, p. xxviii) indicate that declining oil prices, gradual increases in oil consumption and somewhat smaller decreases in domestic oil production are estimated to lead to oil imports that are 50 percent higher than their current level.

Figure 3



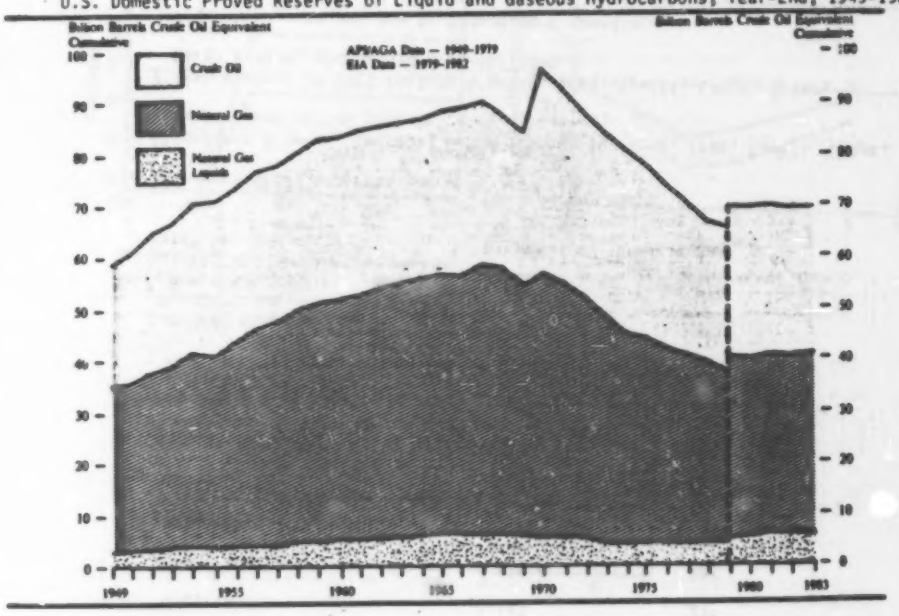
Source: U.S. Department of Energy: Energy Projections to the Year 2010, October 1983.

Figure 4



Source: U.S. Department of Energy: Energy Projections to the Year 2010, October 1983.

Figure 5
U.S. Domestic Proved Reserves of Liquid and Gaseous Hydrocarbons, Year-End, 1949-1983



Source: DOE/EIA. Annual Energy Review 1984. Published April 1985, p. 78.

TABLE 3

U.S. SUPPLY AND DISPOSITION OF OIL AND GAS

	Quad Btu[1/]			
	1984[2/]	1980	1975	1970
Supply				
Domestic Production				
Crude Oil	18.59	18.25	17.73	20.40
Natural Gas Plant Liquids	2.37	2.25	2.37	2.51
Natural Gas (Dry)	17.75	19.91	19.64	21.67
Imports				
Crude Oil	7.25	11.19	8.72	2.81
Refined Petroleum Products	4.10	3.46	4.23	4.66
Natural Gas	0.88	1.01	0.98	0.85
Adjustment	-1.91	-1.53	-.99	-1.59
Disposition				
Consumption				
Refined Products	31.00	34.20	32.73	29.52
Natural Gas	18.03	20.39	19.95	21.79
Total Supply	49.03	54.54	52.68	51.31
Total Consumption	49.03	54.54	52.68	51.31

1/ 1 quadrillion Btu/year = 0.4724 MMBD (million barrels per day) of domestic oil
= 0.4696 MMBD of imported oil
= 2.649 billion cubic feet of gas/day

2/ preliminary

Source: Derived from Table 1 "Energy Supply and Disposition, 1960, 1970, and 1973-1984", DOE/EIA Annual Energy Review 1984, April 1985, p. 5.

TABLE 4

NET IMPORTS[1/] OF PETROLEUM BY COUNTRY OF ORIGIN
1977 AND 1984 (THOUSANDS OF BARRELS PER DAY)

Country	1977	1984
OPEC:		
Nigeria	1,143	214
Saudi Arabia	1,379	321
Venezuela	689	532
Other OPEC[2/]	2,978	944
Subtotal (OPEC)[3/]	6,190	2,011
Canada	446	546
Mexico	155	705
United Kingdom	117	381
Other Non-OPEC	1,657	1,016
Total Net Imports[4/]	8,565	4,660

1/Imports minus exports.

2/Includes Algeria, Ecuador, Gabon, Indonesia, Iran, Iraq, Kuwait, Libya, Quatar, and United Arab Emirates.

3/Arab members of OPEC include Algeria, Iraq, Kuwait, Libya, Qatar, Saudi Arabia, and United Arab Emirates.

4/Figures may not add due to independent rounding.

Source: Derived from Table 44--Net Imports of Petroleum by Country of Origin, 1960-1984, DOE/EIA Annual Energy Review 1984, p. 101.

Although we have significantly decreased our imports of oil compared to the large volumes of the late 1970's and have diversified our foreign sources to minimize disruptive effects from an interruption to our supply, the vulnerability of the United States to an oil import curtailment still exists with potential resultant negative effects on our economic growth. A recent study conducted by the Office of Technology Assessment (U.S. Congress, Office of Technology Assessment. U.S. Vulnerability to an Oil Import Curtailment: The Oil Replacement Capability, September 1984) found that the United States has the technical and manufacturing capability to replace a 3 MMBD (6.3 quad Btu/day) shortfall within 5 years after the onset of a long-term disruption but not without increases in the price of oil and decreased level of economic productivity as measured by the GNP and domestic employment. The technological options which could replace the largest amounts of oil were increased efficiency and switching to alternative fuels to reduce oil use for space and water heating and for steam in industry and electric utilities, and increased average efficiency of automobiles.

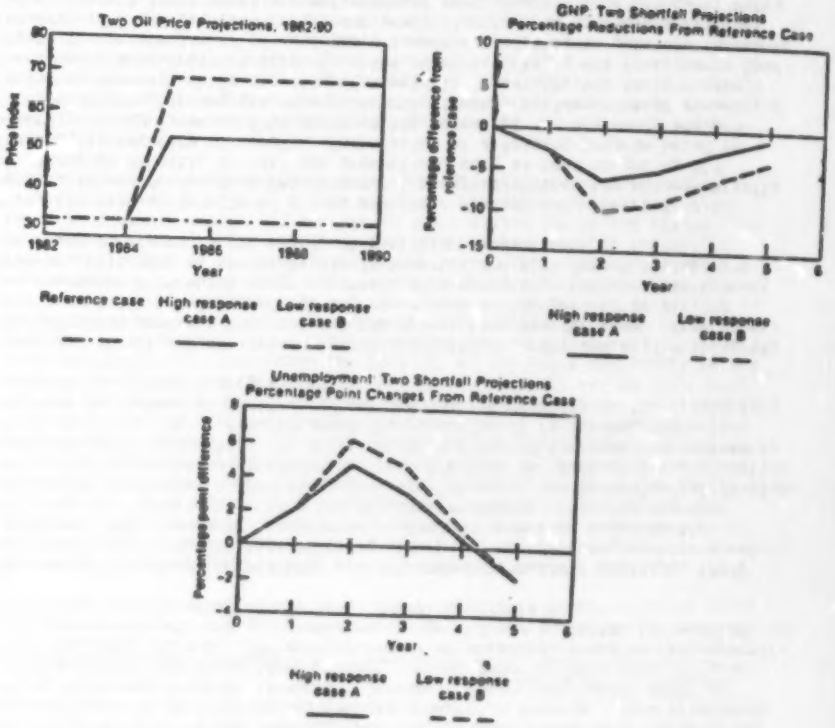
Two oil replacement scenarios were developed by the Office of Technology Assessment which simulated the effects of a 3 MMBD shortfall on oil prices, GNP, and unemployment levels. Figure 6 graphically illustrates the effects of the "Case A" scenario which assumes an adjustment to the shortfall will occur within a 5-year period, and "Case B" which assumes a more constrained response. The average loss in GNP over the 5-year period is significantly less (40 percent) for Case A than for Case B, employment losses are 30 percent lower, and the oil price rise is about one-half as much.

Aside from the effects of a potential supply disruption, imports of expensive foreign oil reduce the economic well-being of the American people. In 1984, the value of crude oil and petroleum products imports amounted to $54 billion. While the value of crude oil remained relatively constant to 1983, the value of petroleum product imports increased by 19 percent (source: DOE/EIA Annual Energy Review 1984, April 1985, p. 31). The 1984 growth in U.S. GNP of 6.8 percent resulted in U.S. oil demand exceeding 1983 demand by approximately 3.5 percent (DRI Inc., Energy Review, Vol. 8, no. 4, Winter 1984-1985). The relative lag in demand for oil is caused in large part by substitution and conservation effects which have yet to run their course. OPEC production for 1984 remained about the same as in 1983 (17.4 MMBD), following four successive years of steep declines (DRI Inc., Energy Review, Vol. 9, no.1, Spring 1985, p. 2).

The current growth in the U.S. economy carries with it the potential for increased energy consumption. The accompanying anomaly of historically high real interest rates has caused the dollar to remain strong, thereby making foreign goods cheaper compared to domestically produced goods. This situation has resulted in increased imports while weakening our export trade. Oil constitutes one important commodity in the import mix.

To the extent that domestically produced hydrocarbons can substitute for higher cost imported crude oil supplies, the effect on our international trade account would be positive. Furthermore, Government revenues generated by OCS development and production result in lower Federal deficits, thereby putting less upward pressure on the dollar and indirectly contributing to a more favorable export climate.

Figure 6
Economic Comparison of Two Oil Replacement Scenarios



Source: U.S. Congress, Office of Technology Assessment, U.S. Vulnerability To An Oil Import Curtailment: The Oil Replacement Capability, September 1984.

As noted in the 1983 National Energy Policy Plan, an adequate supply of energy at reasonable costs "requires a flexible energy system that avoids undue dependence on any single source of supply, foreign or domestic, and thereby contributes to our national security." It recognizes further that the U.S. "is not independent of the energy supply circumstances of our allies abroad. The international dimensions of energy security and emergency preparedness are fundamental aspects of the definition of adequate supply for ourselves."

The development of OCS oil and gas resources contributes to our national security because of its potential to replenish our decreasing domestic reserve base and to displace imports. Availability of supplies within our national jurisdiction reduces our susceptibility to international supply disruptions. The establishment of the Strategic Petroleum Reserve program by the Energy Policy and Conservation Act of 1975 recognized the need to buffer the effects of unforeseen events on oil supplied to our country. At the end of 1984 the Strategic Petroleum Reserve contained 451 million barrels of oil, more than half of the currently planned 750-million barrel system. The 451 million barrels represent approximately 141 days of crude oil imports. (source: DOE/EIA: Annual Energy Review 1984, April 1985, p. 85).

The OCS oil and gas leasing program provides another avenue through private sector development to help meet the nation's continuing oil and gas needs. By adding to our domestically produced supply of petroleum, OCS oil and gas leasing provides a reliable component of this mix which would contribute to our capacity to assist our allies in Europe and Asia. Even though we are less dependent on OPEC oil than our allies, we are still indirectly vulnerable to a disruption of OPEC exports. In such circumstances, all of our non-OPEC suppliers might well reduce oil shipments to us in order to honor their export contracts in an equitable manner. Through the International Energy Agency, the Organization for Economic Co-operation and Development (OECD), and economic summits, the United States has participated in developing collective energy requirements and establishing a framework for international energy security.

Comments were received pointing out the fact that earlier depletion of the U.S. oil and gas resource endowment may reduce dependence on imports in the near term while increasing it in the longer term. This will be particularly the case if the oil and gas endowment of exporting countries is sufficient in quantity and low enough in cost to outlast our domestic endowment. Subsequent discussion of the economics of OCS oil and gas will focus upon the question of when various types of deposits should be searched for and developed. This issue can also be approached by considering whether there is a way of spreading our import dependence over the coming decades that is best for the country. The conceptual framework developed in subsequent sections provides some insights into this question.

4. The Economic Importance of OCS Oil and Gas

In the face of declining domestic proven hydrocarbon reserves and our dependence on foreign sources of oil, the hydrocarbon potential on the OCS represents a significant domestic energy source. In 1984, offshore oil and gas production represented 11.9 percent of total domestic oil production and 25.3 percent of domestic natural gas production (source: U.S. Department of the Interior, Minerals Management Service: Outer Continental Shelf Oil and Gas Leasing and Production Program: Annual Report Fiscal Year 1984, March 29, 1985, p. v.). The average amount of unleased, undiscovered economically recoverable oil and gas resources on the OCS are estimated to be about 18 billion barrels of oil equivalent (BBOE) (see Table 5).

The sources of these hydrocarbons are heterogenous in their location, their size, and their probabilities of being economic. Furthermore, an assessment of economically recoverable resources is dynamic over time based on the influence of factors other than the physical resource. Changing economic conditions, reflected in price changes, cost changes, and technological developments, influence the magnitude of our resource base in terms of its exploration and development potential. In addition, production of the resource ordinarily involves a time lag of 5 to 15 years from the time it is leased, indicating the need to address projections of oil and gas requirements in the future in formulating a leasing program today.

Consumers of oil and gas are concerned about the security and availability of the petroleum products they use and the prices they pay for them. They have little specific knowledge of the source or cost of the particular oil and gas resources from which their purchases were produced. Consumers do know, however, that some of the crude oil is imported and that import disruptions can cause shortages in the supply of petroleum products.

Given the near uniformity of prices and their dominance by the world oil market, it would seem from the consumers' perspective that the primary benefit of increased domestic oil and gas production, such as that sought by OCS leasing, is security of supply. Formulation of a leasing program based on security of supply would thus focus on the potential for discovery and production of more oil and gas resources without much consideration of economic factors. However, while security of supply is important, two factors make it reasonable to consider economic gains as well. First, all investments leading to the production of oil and gas are made in response to potential economic returns. Oil and gas resources whose production does not yield a sufficient return on such investments are not produced even though they might contribute to a larger supply of secure domestic oil and gas, at least for a number of years. Second, the economic efficiency with which we produce new OCS oil and gas may be as important as security of supply to our economic well-being. Further, national security itself can be enhanced by economically efficient development of our oil and gas resources. It is thus appropriate to consider economic benefits in formulating a leasing program.

The importance of economic efficiency can be illustrated by examining the role of oil and gas in our economy from the perspective of a resource owner and producer (which is the role the Federal Government performs on behalf of the public). The overall productivity of the U.S. economy, its ability to generate the income and the goods and services that we enjoy as consumers, depends on the success of many individuals and businesses in producing things that have value greater than the costs incurred. The bigger this difference, the greater the productivity of the U.S. economy and the higher our citizens' standard of living. The same principle holds for production of oil and gas. Economists call the allocation of resources that yields the greatest value an economically efficient allocation.

The economic benefit from producing OCS oil and gas instead of importing an equivalent amount can be seen by considering costs. The cost of an economic activity is the sum of the values of the various resources (labor, materials, energy) which are used in its conduct. The commitment of resources to one use usually excludes their use in the production of other goods and services. Since a market economy uses dollars to keep track of costs, the use of $20 worth of resources to find and produce a barrel of oil from the OCS means that at least $20 worth of other goods and services has been foregone. Similarly, if $30 is paid to a foreign country for a barrel of oil, then that country can remove $30 worth of resources or goods and services from the U.S. economy. The economic benefit from producing the OCS oil instead of importing oil is, in this case, the $10 of resources available to produce other goods and services for U.S. consumers that would not be available after importing the foreign crude oil. In more formal terms, the economic benefit of OCS oil and gas production is the difference between the production revenues valued at market prices and the costs of the resources used to find, produce, and transport to market the oil and gas produced.

As consumers, we cannot distinguish between gasoline made from imported crude oil and gasoline made from less costly OCS oil. Both sell at the same price and burn in the same way in our cars. As owners of crude oil resources, however, we can tell the difference between producing crude oil that costs more versus crude oil that costs less. Since both sell at the same price, a price determined by the world oil market and transportation costs, a low-cost oil reservoir yields higher profits to its owner than a high-cost reservoir. Higher profits to the owner mean correspondingly higher benefits to the economy whether the owner is a private firm or the Federal Government.

If all oil and gas deposits (the word "deposits" is used interchangeably with "fields" and "prospects") on the OCS were to cost the same to find, produce, and transport to market, then the decisions leading to their development would tend to be all-or-nothing decisions. Either all of the deposits would yield oil costing less than expected prices and would be profitable to develop, or all would yield oil costing more than expected prices and none would yield any net economic value. However, the costs of producing OCS oil and gas deposits differ substantially depending on such factors as water depth, geological characteristics, the size and quality of the deposit, and site-specific

difficulties in exploration and development activities. Some OCS oil and gas deposits have costs (appropriately calculated at time of production or in present value terms) of $5 per barrel, some $20 per barrel, and some $100 per barrel of oil recovered. Under given oil and gas prices and geologic risk, different oil and gas deposits yield different economic benefits because of the cost differentials.

If the cost of each deposit were known and future prices were known, it would be a straightforward task to determine which deposits would yield economic benefits and how much. Deposits with costs per barrel less than oil prices per barrel would yield profits for owners and producers, and benefits to the U.S. economy. Other deposits, which although taken together would probably contain much of the oil and gas in nature's endowment, would yield no profits and if developed at costs greater than prices would actually reduce the income generated by the U.S. economy.

This perspective of the economic gains from OCS oil and gas production can be applied to the objective of secure supplies. As will be discussed below, there is probably enough oil and gas in place within the United States (not to mention coal and other energy resources) to allow domestic production levels sufficient to reduce oil imports to zero. This fact makes energy independence a tempting goal. The reason the United States has not achieved complete energy independence is not that there are inadequate quantities of energy resources in the natural endowment of the United States. Rather it is that the economic and environmental costs that would be incurred in producing those resources are higher than the benefits of gaining a completely secure supply. While the security benefits of reducing imports are an additional gain to the direct economic efficiency benefits of OCS oil and gas production as defined earlier, there is a limit to the economic (and environmental) costs worth incurring to reduce oil imports. This limit might call for the development of some oil and gas resources that are not economical in terms of market prices and costs, but this additional development is not likely to allow the complete elimination of oil imports. Although the OCS leasing program is not likely to eliminate oil imports, it can help to bring about an economically appropriate amount of import reduction by allowing investments that reflect the different costs of oil and gas in various deposits.

Leasing OCS oil and gas resources is not as simple as merely deciding which deposits to produce and which to leave in the ground. Exploration and development decisions are continuously being made even as prices and costs change. Higher oil and gas prices make higher cost resources worth producing; lower world oil prices make investments in production of higher cost resources unprofitable and tend to reduce domestic production and increase oil imports. Since the production that results from leasing occurs over many years in the future, it is not oil and gas prices now or at the time of a lease sale that will affect production and economic benefits, but prices 10 to 30 years from now. Uncertainty about future prices makes it impossible to determine now precisely which unleased, undiscovered oil and gas deposits should or should not receive investments at any future point in time.

Despite this uncertainty, it is possible to develop a reasonable approach to formulation of a leasing program considering economic benefits. This approach emerges from the way exhaustible resources are generally developed. In the absence of international politics and other imperfections in world energy markets, there would be a tendency for oil and gas prices to increase gradually over the long run as demand was met from increasingly more costly deposits. (This tendency may be partly offset by technological developments that reduce costs, or it may be accentuated as world oil demand grows.) In general, there is a way of sequencing the development of oil and gas deposits of differing costs to yield the greatest benefits to resource owners (like the Federal Government) and to the economy as a whole. Such a sequence develops deposits in order of increasing costs, conserving higher cost resources for later periods when resource prices are higher because lower cost resources have been depleted. This concept of resource development will be discussed in more detail in section V.

It is an ironic fact that the benefits from an economically efficient sequence of OCS oil and gas resource development, given a path of world prices beyond our control, accrue to the American people primarily in their roles as owners of the resources on Federal lands, but not in their roles as consumers. Thus, while security of oil and gas supply is of concern to the public as consumers, the economic efficiency of producing our domestic supply is of concern to the public as owners of OCS oil and gas. A major consideration, therefore, in the formulation of a 5-year OCS oil and gas leasing program is its effect on the sequencing of economic activity involved in OCS development and the economic gains that result. Leasing programs that result in a sequence of development that is closer to the economically efficient sequence will yield greater benefits to the U.S. economy as well as greater revenues to the Federal Government.

The availability and price of oil on the world market are determined by a combination of factors, some political, some economic and some geological. Taken together, these factors will determine the costs to the U.S. economy of using imported oil at various times over the coming decades. They may also result in periods in which imports are curtailed, forcing the U.S. economy to operate without oil it would otherwise be able to purchase.

The amount of oil imported by the U.S., assuming that there are no supply curtailments, will also depend on a combination of factors and will vary with time. In general the total amount of oil demand will decrease as prices increase and vice versa. Similarly the amount of oil and gas discovered and produced domestically will tend to be higher during periods of higher oil prices and lower during periods of lower oil prices.

The extent of discovery of additional domestic deposits depends, of course, on the nature of the oil and gas resource endowment. It may turn out that there are substantial deposits waiting to be found in higher cost areas. If so, when higher oil prices make investments in exploration in such areas worthwhile, these deposits will be added to the U.S. reserve base and will contribute to production. If it turns out that there are few such deposits, then investments in exploration will be dampened by the negative results of drilling and more oil will be purchased on the world market. Since changes in both demand and supply depend to a substantial extent on capital investment decisions, there is a time lag between price changes and changes in production and consumption.

The working of oil and gas markets thus will adjust the extent of U.S. imports to many factors. In general, during periods of lower world prices, the economy will use more oil, find and produce less and import more. The very conditions in the world market that seem favorable--ample and diverse production of oil and lower prices--can only be of benefit to the U.S. economy if we import more oil, which, of course, makes the economy more vulnerable to supply curtailments and less well prepared for future price increases.

The question of how to spread our reliance on imported oil over coming decades can thus be seen as a question of balancing the economic productivity gained by using cheaper imported oil during times when world prices are lower against the potential costs of supply disruptions. Furthermore, it is quite possible that the total U.S. endowment of oil and gas resources will not be sufficient in amount and low enough in cost for production to keep pace with demand throughout the coming decades during which relatively low cost reserves in the Middle East and elsewhere are depleted. In light of this, Government policies could be used to shape, to a limited extent, the workings of the market and the allocation over time of domestic production and imports. Economic policies such as import tariffs, gasoline taxes or lower taxes on the oil and gas industry could shift some discoveries and their production to earlier times. A restrictive leasing program could shift discoveries and production to later times. At present there is no national policy that would provide the basis for substantial shifts of this sort in either direction. A leasing policy that would result in less exploration and production (with greater imports) in the short-to-medium term than would the workings of the market, implemented in order to have greater production (with less imports) in the long term, would need to be based upon an analysis showing that this would best meet the nation's energy, economic, and national security needs. To do so requires a more detailed examination of the nature of oil and gas resources, the workings of the market for these energy resources and the possible geopolitical scenarios that are likely to influence the available supply of imports.

V. Resource Characteristics and the Economic Principles of Leasing

A. Introduction

This section discusses the economic characteristics of OCS oil and gas resources and sets forth a general rule for sequencing their development that would maximize their contribution to the economic well-being of the citizens of the United States. This sequencing rule is developed first for a highly idealized situation. Then the discussion addresses the major differences between the actual and the idealized situation and the implications for Federal leasing programs.

B. Resource Characteristics

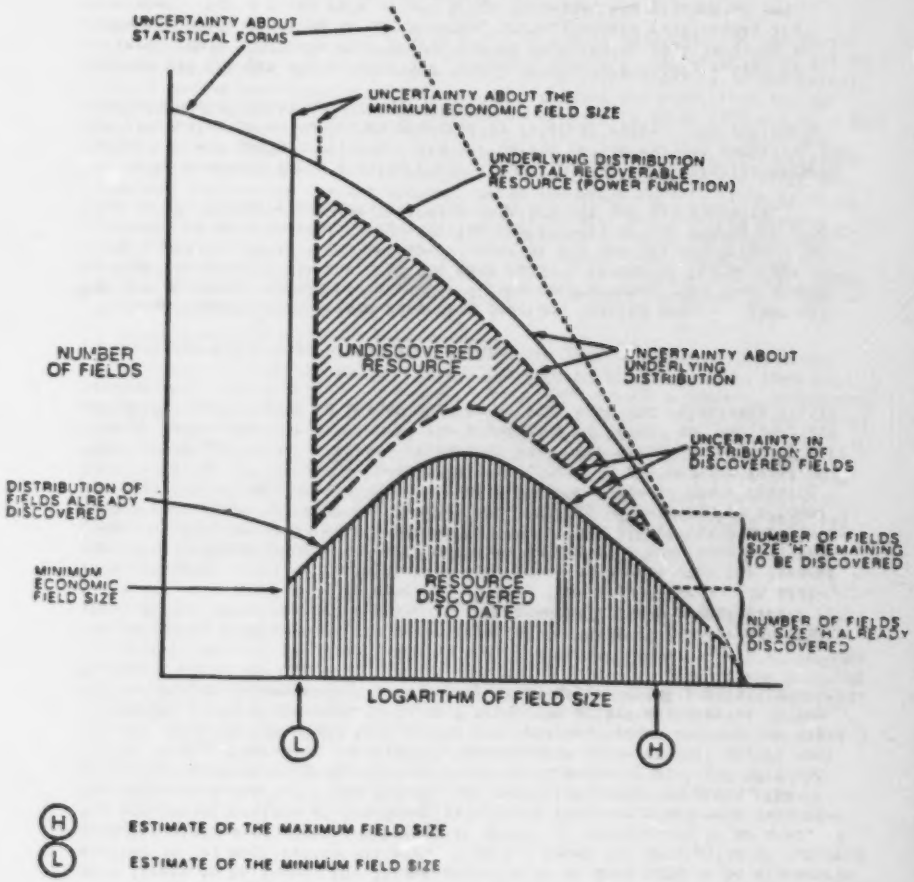
The physical and geologic characteristics of the oil and gas resources of the OCS are primary determining factors affecting their development and economic benefits. Oil and gas deposits (or fields) differ in many ways: the chemical and physical properties of oil and gas vary as do their proportions in a deposit; reservoirs differ in a number of characteristics that affect the ease of extracting oil and gas and the costs of production; the costs of basic operations such as drilling wells, installing production platforms, and transportation facilities differ from location to location; and the potential and actual amounts of oil and gas vary from deposit to deposit. For simplicity of discussion, it is helpful to focus on cost differences due to deposit size and location of the resource. This concept is described in more detail in the area-by-area analysis of resources and net economic value in sections VI and VII of this Appendix.

The results of oil and gas exploration in currently producing areas show a wide range in deposit sizes. For example, discoveries in the Gulf of Mexico out to 200 meters in water depth range from those with a few tens of thousands of barrels of hydrocarbons to those with approximately 1 billion barrels of hydrocarbons, varying by a factor of 100,000. In general, there are only a few giant oil fields, more medium-sized fields, and many more small fields in a hydrocarbon-bearing area. (A field, or in this discussion a prospect, is an area that is an actual or potential site of hydrocarbon deposits.) Figure 7 illustrates a schematic of the distribution of resources typical of a petroleum-bearing area.

Because of economies of scale, the cost per barrel of finding and producing oil generally decreases as the size of the deposit increases. Within an area in which the locational factors affecting cost are roughly the same, larger deposits will have lower per-barrel costs and higher net economic value per barrel. These relationships are shown in Figure 8. Area A in Figure 8 is the least costly location while Area C is most costly. At given oil and gas prices, the costs of operations in a particular area make oil and gas deposits which are smaller than the minimum economic deposit size uneconomical to find and produce. In lower cost areas such as the shallower areas of the Gulf of Mexico, relatively small deposits are economic while in higher cost areas such as Beaufort Sea, or the deepwater Atlantic, only the larger deposits are economic at prices within currently expected ranges.

FIGURE 7

SCHEMATIC REPRESENTATION OF CONCEPTS USED IN FIELD DISCOVERY MODELING



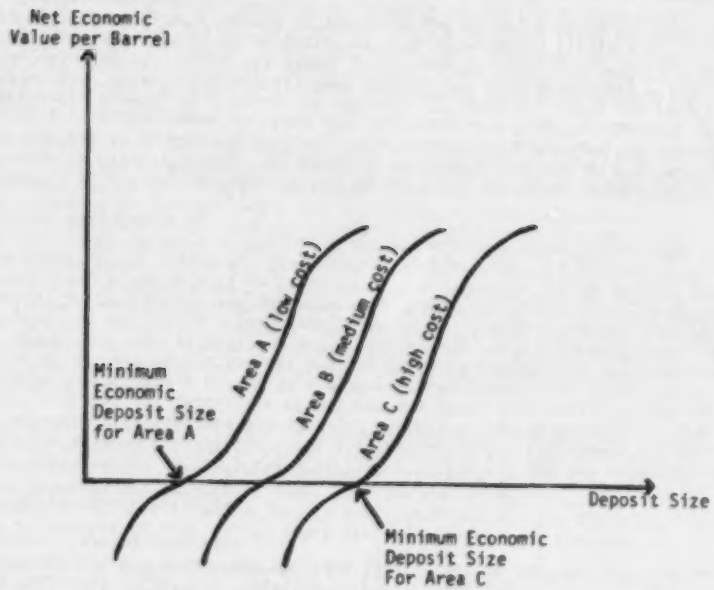
H ESTIMATE OF THE MAXIMUM FIELD SIZE

L ESTIMATE OF THE MINIMUM FIELD SIZE

Source: Frank Morra, Jr., and Stephan Peth. Short-term Projections of Offshore Petroleum and Natural Gas Production and Costs. Gas Research Institute, Chicago, Illinois. May 30, 1984.

FIGURE 8

GENERAL RELATIONSHIP BETWEEN DEPOSIT SIZE, COST REGIME, AND NET ECONOMIC VALUE PER BARREL



Because they yield greater returns on investments in exploration and because their size makes them easier to identify through predrilling exploration and more likely to be found, the larger deposits in an area tend to be discovered earlier in its exploration history. Figure 7 shows the population of resource deposits discovered after a substantial amount of exploration in an area. A far greater percentage of the few giant fields has been discovered than of the medium and smaller sized fields. In currently producing areas, the population of undiscovered resource deposits is probably depleted of giant fields, e.g., those with the highest net economic value as well as the most oil and gas. On the other hand, there are numerous medium and smaller sized fields yet to be discovered. Figure 9 shows the actual discoveries in the Gulf of Mexico in comparison to one projection of the total population distribution.

The unleased, undiscovered resources expected to exist in the various OCS areas differ for a number of reasons. Because of different geological histories, the population of deposits differs from area to area. In addition, the high costs of operations in some areas have made even the largest deposits in those areas uneconomic with the result that none have been discovered, while in lower cost areas it is likely that all of the giant fields have already been discovered. Finally, the history of leasing has allowed more leasing and exploration in some areas than in others. Since leasing tends to focus on the larger prospects first, just as exploration tends to find the larger deposits first, areas that have been leased extensively will tend to have a smaller portion of the population of larger and medium-sized prospects remaining to be leased than areas that have had relatively little leasing.

C. Economic Principles of OCS Investments

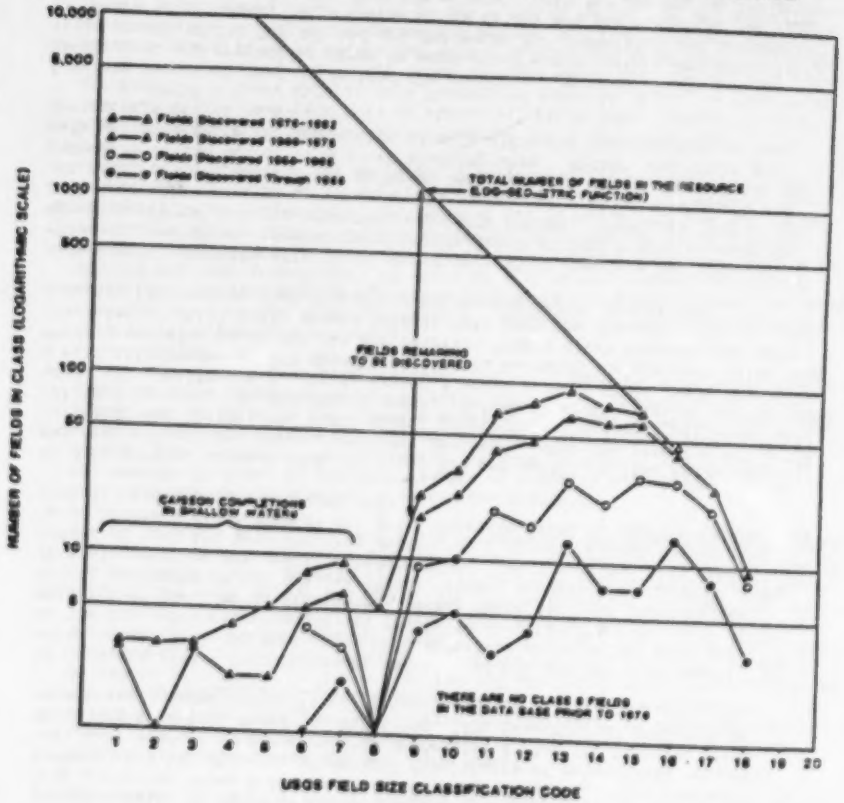
Concerns have been raised regarding previous leasing programs that oil and gas resources should be saved for future generations, that they should be left "on deposit" in the OCS, and that rapid offering of OCS acreage for lease could result in premature development of oil and gas resources. Such concerns can be addressed by considering the effects of the timing of production on the economic benefits realized from OCS oil and gas deposits.

The basic concepts for analyzing these issues involve relationships between future oil and gas prices, the costs per barrel of the various deposits, and the time value of resources as measured by interest rates. The following discussion elaborates upon these notions.

Because oil and gas are exhaustible resources that are highly valued by society, their long term real prices can be expected to rise relative to renewable goods produced in our economy, until adequate substitutes are developed. For a given rate of oil price increase, the discounted net economic value (benefits) from production (i.e., the present value of revenue less production costs) of a particular deposit would increase or decrease if it were postponed, depending upon whether the deposit was high or low in costs. In general, the smaller the net benefit per barrel of production

FIGURE 9

DISTRIBUTION OF FIELDS THAT HAVE BEEN DISCOVERED AND REMAIN TO BE DISCOVERED IN THE GULF OF MEXICO



Source: Frank Morra, Jr., and Stephan Peth. Short-term Projections of Offshore Petroleum and Natural Gas Production and Costs. Gas Research Institute, Chicago, Illinois. May 30, 1984

Note: In the USGS field size classification, Class 8 fields have 380,000 to 760,000 BOE while Class 18 fields have 388.6 million to 777.2 million BOE. The upper limit for each class is twice the lower limit.

from a given oil and gas deposit at a given point in time, the greater the interest rate it will earn under a given path of future price increases. However, while high cost deposits with small per barrel net benefits earn relatively high interest rates today if left in the ground, as the accumulated interest swells the net benefit over time, the interest rate (i.e., the growth rate in net benefits) decreases.

These effects can be illustrated by a set of simple examples. In the first, oil can be produced at $28 per barrel from a deposit. If the price of oil is $30 in the current year, the net economic value of this oil is $2 per barrel. If oil prices are expected to increase at 1 percent per year, then the net economic value of this oil if production is delayed is $2.30 ($30 x 1.01 - $28) per barrel in the second year, $2.60 ($30 x 1.01^2 - $28) in the third year and so forth. The effective interest earned by leaving oil in this reservoir on deposit in the ground is 15 percent (0.30 ÷ 2.00 x 100) in the first year. However, even though the net economic value increases rapidly (from $2.00 in the first year to $4.16 in the eighth year), because the interest payment increases slowly (from $0.30 in the first year to $0.32 in the eighth year) the effective interest rate declines. In the second year, leaving oil on deposit yields 13 percent (0.30 ÷ 2.30 X 100) while in the eighth year, postponing production for a year yields only a 7.7 percent (0.32 ÷ 4.16 X 100) gain in economic value.

A second example illustrates the situation for lower cost oil. If oil can be produced at costs of $20 per barrel and sold at $30 per barrel, then the net economic value is $10 per barrel. For oil from such a deposit, postponing production for a year while oil prices increase 1 percent to $30.30 per barrel yields a gain of only 3 percent. Generally, such a deposit should be put into production immediately. While these examples are highly simplified, they show the significant differences in the gains in value that result from leaving economically recoverable oil of different benefit to the country on deposit in the earth while oil prices increase. (If oil prices are expected to remain constant or decline for an extended period of time, the direct economic benefits of leaving positively-valued resources on deposit may be eliminated.)

An imaginary manager of all the deposits on account in the OCS bank with the authority to leave them or withdraw them for reinvestment at any time could reasonably use the following logic in making such decisions. The U.S. economy yields a return on resources of, for example, 8 percent. This is one accepted value for the discount rate used in the Government's economic decisionmaking. Any deposit in the OCS that would earn more than 8 percent interest under the oil price expectations at a given time should be left in the OCS bank. Any OCS deposit yielding less than 8 percent effective interest should be withdrawn from the bank and its value invested in the economy instead. In the examples above, oil from the $28 per barrel reservoir would be left in the ground until the eighth year while the oil in the $20 reservoir would be produced in the first year.

An OCS manager in this highly idealized situation would reap the greatest economic value for the nation's economy by keeping an inventory listing of each OCS oil and gas deposit with estimates of its benefits if developed beginning in the present, and the rate of growth in its benefits that would result from postponing development under expected future oil and gas prices. As oil prices increase, formerly uneconomic deposits become economic. Whenever the growth rate on a given deposit's net benefits dropped below the discount rate, it would be economically producible and the manager would take action to bring about development of that deposit. This concept is in keeping with the theories of optimal development of exhaustible resources that have emerged in the economics profession during the 50 years since Hotelling's seminal paper (H. Hotelling, "The Economics of Exhaustible Resources," Journal of Political Economy, 39, April 1931, pp. 137-175).

It is worth noting that while the sequence of oil and gas development that would result from application of this principle would be the most beneficial to the U.S. economy, it would not result in very large net economic values measured at the time of development unless there had been unanticipated, abrupt increases in oil and gas prices, abrupt decreases in costs or unexpectedly positive new geologic information. The reason for this ironic result is that the benefits from developing a deposit cannot become very large before a given gradual oil price increase fails to yield a growth rate that is less than the discount rate.

To demonstrate, suppose that oil costs $20 per barrel to find and produce, and real oil prices rise by 1 percent per year. When the starting oil price is $22.86 per barrel, the first year's growth in net economic value per barrel is 8 percent. In subsequent years, the annual growth rate in net economic value will decline, e.g., to 7 percent 3 years later. Under these conditions a rational manager of OCS deposits trying to maximize the economic gains from their production would not let the benefits from a given deposit grow past the point at which their growth rate is less than the discount rate; in this example, that occurs when the oil price reaches $22.86 per barrel.

Before discussing the effects of uncertainty about resource deposits and economic conditions, several important features of this idealized rule for managing OCS oil and gas resources are worth noting. First, as long as oil prices or costs or both are expected to change, production of OCS oil and gas resources are never final go/no-go decisions for all of the oil and gas endowment of the OCS or of a given planning area. Rather, decisions are made which sequence the production of many different deposits over a long period of time.

A second important feature is that the resulting sequence of oil and gas development and production saves an economically appropriate and potentially large amount of the OCS oil and gas endowment for production and consumption by future generations. This conservation of oil and gas resources for future generations results directly from the economic rule for sequencing the production of various deposits. Such conservation, however, is not readily apparent in most discussions of resource scarcity and development. In the idealized situation for which the rule was developed, the OCS manager has a known inventory of all the oil and gas deposits in the endowment. At a given point in time, he could group these deposits into three groups:

A. Uneconomic deposits: those that are not economical under the prices expected during the upcoming production period. (Costs exceed price on these deposits.)

B. Marginal economic deposits: those that are economical but whose net benefits are growing at a rate greater than the discount rate.

C. Economic deposits: those that are economical and whose net benefits would increase at a rate less than the discount rate.

The idealized manager would bring the deposits in group C (economic deposits) into production in the current period under the rule of sequencing. He would save deposits in group B (marginal economic deposits) for development within a relatively few years. The uneconomic deposits in group A would be postponed from production for many years or decades as seen from the manager's current decision point. A manager who knew the amount of resources in group A and the costs of production from the deposits containing them would be able to give a clear picture to current generations of the amount of resources which would remain for future generations.

A third feature of resource management by the designated sequencing rule is that it yields the economically most beneficial sequence of development and production for a given path of future oil and gas prices and operating costs. Actual price changes also can be reflected in the manager's subsequent decisions using the sequencing rule even if these prices have not followed expectations.

Because of the abrupt and unanticipated oil price changes of the last decade or so, it is worth examining how a manager using this sequencing rule would react to such price changes. Assuming that the sequence of development prior to a price increase has followed the rule, the manager would have his inventory of nonproducing oil and gas deposits divided into groups A, B, and C as described earlier. An abrupt and unanticipated increase in oil prices, assuming that it would raise prices throughout the upcoming production period but leave the rate of price increase during that period unchanged, would cause him to regroup his deposits. Numerous deposits would be shifted from group B to group C because they would now yield such great net benefits that future price increases would not increase them at a rate greater than the discount rate. Of course, deposits that were already in group C would now yield even greater benefit from production than anticipated when they were first classified as ready for development. In addition, some of the uneconomic deposits in group A, those that were close to being economical before the price increase, would be shifted to group B. A large enough price increase could make some deposits that were uneconomic shift directly from group A to group C.

The effect of an abrupt and unanticipated oil price increase is thus to greatly increase the number of deposits economically ready for development and to substantially increase the net benefits which the economy can realize from the production from these deposits. The manager under these conditions would reasonably be expected to substantially increase the pace of development in order to realize these net benefits.

Other unanticipated changes in oil prices could occur. For example, some external factor could cause an increase in the long run rate of oil price growth. This would cause shifts in the grouping of oil and gas deposits similar to the abrupt price increase scenario, but the increased long-term price growth rate would reduce the extent of shifting from group B to group C. A higher rate of future oil price increase means that the optimal time for bringing a given deposit into production would be later. A very large increase in the long-term rate of future oil price growth could, in fact, shift some deposits from group C to group B for a period of time.

Recent price trends in the world oil markets show the possibility of a decrease in the rate of future oil price growth. If the OCS manager were confronted with an unanticipated leveling off of oil prices for the coming production period after expecting continued increases, he would find it necessary to regroup his inventory of deposits, moving some from group B to group A and some from group B to group C. The deposits moved to group A would be those that were barely economical given the higher prices that were expected later in the production period. Without such continued increases, such deposits become uneconomical.

On the other hand, some deposits that were increasing in value under previously expected price increases would be shifted to group C because there is no longer any increase in the economic benefits to be had by waiting for higher prices. Thus, an unanticipated leveling off in the rate of future price growth, like an abrupt, unanticipated increase in prices, could bring the OCS manager to order an increased number of deposits into production in order to achieve the greatest gain for the economy.

In the previous discussion of the ideal sequencing and timing of investments and the resulting production from the various oil and gas deposits of the OCS, two assumptions have been implicit: (1) that oil and gas prices adequately reflect the value of oil and gas to the U.S. economy and (2) that the costs incurred by lessees adequately reflect the costs to society of exploration, development, and production activities. It is likely that there exist benefits from domestic oil and gas production that are not well reflected in world oil prices as well as social costs that are not reflected in the market costs of oil and gas operations. The social costs are analyzed in Appendix I. The possible external benefits (or positive externalities, as economists call them) from producing oil and gas and reducing oil imports have received growing attention during the past five years.

The concept of an "oil import premium" was formulated in the 1970's for the purpose of analyzing the economic impacts on the domestic economy from changes in the U.S. demand for imported oil. Potentially the most important component of the premium is the effect of changes in U.S. demand on the world price of oil. Additional effects involve changes in inflation rates, balance of trade measures, and national security considerations, none of which are reflected in the oil price. For our purpose, changes in the demand for imports emerge from changes in OCS production. Hence, for each potential barrel that might

be generated domestically, the import premium can be added to the net economic value of a marginal barrel to obtain the total economic value of replacing imports with OCS supplies.

Suppose that, in the world oil markets, elasticity of demand is -0.4, while elasticity of supply is 0.1.* These figures are consistent with those used by Horwich and Weimer and other analysts in the mainstream of the issue. (See Horwich, George and David Leo Weimer. Oil Price Shocks, Market Response, and Contingency Planning. American Enterprise Institute, Washington, D.C., 1984. p. 72.) If oil prices are at $30 a barrel and world oil production is 50 million barrels per day (Mbbl/d), a one barrel increase in production can be shown to cause the market price to drop by $0.0000012 to $29.9999988 per barrel. But for the market as a whole, the $0.0000012 multiplied by 50 Mbbl/d translates into $60 less being paid worldwide by consumers for their oil and $60 less being taken in by producers.

When the analysis is restricted to one importing country instead of the world, some of this $60 can be included in valuing the marginal barrel supplied. If U.S. imports are running at 5M bbl/d, then the fall in price resulting from the additional barrel of domestic supply means that U.S. consumers will be paying as a group $6 less to foreign producers. If marginal domestic production costs are $10 per barrel, the incremental barrel produced is worth $26 to the United States, not just $20 ($30-$10 + $6). The extra $6 is the marginal import rent (or marginal price effect of the import premium). This transfer from foreign producers to consumers is spoken of as a transfer of economic rent. If supply increases or demand falls, the market price falls, and there is a transfer of rent from producers to consumers; if supply decreases or demand increases, there is a transfer the other way.

In addition to the import rent effect discussed above, other components have been identified which measure a more comprehensive "import premium." One is a "disruption component," extending the import rent analysis to allow for different import levels and supply and demand sensitivities during a supply disruption, given certain levels of public and private inventories. To the extent that additional domestic production substitutes for imports, the effect of price changes in oil markets as well as secondary effects in other markets may be dampened during a supply disruption. Indeed, with a reduction in imports, both the likelihood of a disruption itself and the required size of the public stockpile may be reduced (or the protection afforded by the existing stockpile might be increased). For a long-run increment in oil supply, the value of the marginal import rent would have to be adjusted for the proportion of the increment's lifetime that could be expected to be affected by disruptions, and the value to the economy from reducing the disruption and inventory costs.

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* The relationship between prices and quantities supplied or demanded is often expressed in the form of an "elasticity". A demand elasticity of -0.4, for example, means that consumers will want 0.4 percent less oil for every 1 percent increase in oil prices. A supply elasticity of 0.1 means that producers will want to produce 0.1 percent more oil for every 1 percent increase in prices.

Other components of the import premium incorporate various macroeconomic effects. One, an inflation component, translates import demand reductions into an effect on the inflation rate and then back to a measure of national income for the effect per incremental barrel produced. Another major macroeconomic component measures a balance of payments effect, which is the improvement in the balance of trade resulting not from any rent transfer nor from the change in oil prices but rather from the effect of incremental domestic supply on the aggregate import bill and subsequently on another measure of national income. Both the inflation and balance of payments components are somewhat controversial, requiring seemingly speculative assumptions and possibly involving some double counting.

Taking into account these various conceptual components, some analysts have estimated import premiums as high as $124 per barrel. (See: Broadman, Harry G. Review and Analysis of Oil Import Premium Estimates, Discussion Paper D-82C. Resources for the Future, Inc., Washington, D.C., 1981. p. 5-2.) Other analysts, however, exclude the macroeconomic effects, focusing instead on the market effect of a reduction in U.S. import demand (from incremental domestic production) on world oil prices. Their conservative estimates of the premium are generally below $10 per barrel. (See: Bohi, Douglas R. and W. David Montgomery. Oil Prices, Energy Security, and Import Policy. Resources for the Future, Inc., Washington, D.C., 1981. p. 134.)

Considering the range of estimates and the difficulties in arriving at realistic assumptions, a precise quantitative measure of the import premium is not very trustworthy. It should be noted, however, that the estimates of Net Economic Value in this Appendix are conservative because they do not incorporate any amount for the value of the import premium.

In deciding the timing of investments in oil and gas prospects on the OCS, the idealized manager would thus need to add estimates of the external benefits to estimates of net economic value. At a given point in time, this would affect all prospects being considered for investment by increasing oil and gas prices. If the import reduction premium were expected to increase over time because of the expectation that oil prices or imports or both would increase, then the manager's forecast of future oil and gas price trends could be adjusted appropriately. By calculating benefits using prices adjusted for the effects of the import reduction premium, all of the observations of the previous discussion based on prices, benefits per barrel and costs then hold. The sequencing rule then can be applied using estimates adjusted for the import reduction premium.

At this point in the discussion, the question of the timing over coming decades of production and imports can be addressed once more. Assuming that the idealized manager had properly estimated the import reduction premium for future years, his application of the rule for determining the timing of investment in each prospect would yield exploration, development, and production that would best meet the Nation's energy and economic needs. In particular, it might shift oil and gas production from periods in which it would be best based on market prices alone to other periods when it would be best based on market prices and the import reduction premium combined.

Although it is quite difficult to estimate the import reduction premium for future years, it is possible to assess its general relationship with regard to possible future scenarios. The adjustments to the ideal path of development resulting from market prices alone can then be assessed. For example, if the import reduction premium is currently rather small, but is expected to grow significantly over the next two or three decades, then the adjusted base prices for calculating benefits would be little different from current market prices, but the rate of adjusted price increase would be greater than the rate of market price increase. In general, for some prospects, the time at which they are mature for investment would be shifted to later years by such an adjustment. This situation might result if the economy was expected to become gradually more vulnerable to import disruptions over coming decades. This could emerge from the failure to develop : (1) more energy efficient capital, (2) more efficient substitute energy supplies, (3) oil and gas reserve bases sufficient to keep imports from growing, or (4) strategic petroleum reserves sufficient to offset the effects of an import disruption. The more likely such a scenario were to evolve as time passed the more an idealized manager of the OCS would stretch out investments in prospects with high unit costs.

It is possible that the trend in the import reduction premium could be flat or even declining. This would reflect expectations that the economy would continue to develop a capital structure that is more energy efficient and that allows substitution of alternative energy supplies. Or it could reflect a judgment that the likelihood or size of an import disruption was decreasing over time. A flat, moderate import reduction premium would require little adjustment in the timing of investments and production on the OCS. A declining premium would require somewhat earlier investments in some prospects.

Although this discussion has offered no definitive answer to the issue of the best timing of investments and resource depletion, it has at least provided some insights by relating an idealized management rule to some of the trends which affect the future. Subsequent discussion will address the role of market decisions in the same framework.

The Secretary, as manager of the oil and gas resources of the OCS, confronts an actual situation that makes it impossible to follow exactly the course of an idealized manager. By examining the differences between the actual and idealized situation, it is possible to develop a reasonable adaptation of the idealized priciples of leasing.

Imperfect knowledge of oil and gas resources is an inherent limitation in managing OCS oil and gas resources. Oil and gas deposits on the OCS are hidden from view under hundreds or thousands of feet of water and thousands of feet of the earth's crust. Actual deposits can only be discovered through drilling costly exploratory wells. Prospects, which are geological features that could contain oil and gas deposits, can be identified through the analysis of seismic data. Given the large area of the OCS and the relatively small area of most prospects, substantial cost is incurred in identifying prospects. Seismic surveying and exploratory drilling are the basic investments that are made in the search for oil and gas. They must be made with the recognition that often they will not yield discovery of oil and gas deposits. Many prospects are identified that, on closer evaluation, do not warrant an investment in exploratory drilling. Many prospects that are drilled turn out to contain no oil and gas. Others are found to contain oil or gas but are not economically producible because of the size and character of the deposit. In addition, individuals and groups differ in identifying and evaluating prospects. Many prospects go unseen through numerous seismic surveys and evaluations. Others are identified by only one of the many firms searching an area.

In the idealized situation described earlier, the OCS manager had a known inventory of all deposits. In actuality, the Department of the Interior has an incomplete and uncertain inventory, not of actual deposits, but of identified prospects and aggregate resource potentials. Where the idealized manager saw deposits shifted within his inventory depending upon economic expectations, the actual inventory of unleased, undiscovered recoverable resources also changes over time as the state of knowledge evolves from investments in seismic evaluation and exploratory drilling. The search process continually adds prospects to the inventory as they are identified, drops them as they are leased or condemned by further seismic evaluation or drilling, and recharacterizes their resource potential and costs. Thus, the actual knowledge of OCS oil and gas resources on which leasing decisions are based is not final or definitive.

One important limitation on knowledge of oil and gas resources is the lack of data on very high cost (per barrel) deposits. In particular, almost nothing is known about the uneconomic resources in group A. They are excluded from estimates of "undiscovered recoverable resources" such as those published by the U.S. Geological Survey, MMS, and oil companies, because they are not economically recoverable. In fact, since resource information is a by-product of investments in the search for economically recoverable oil, little data exist on deposits having costs substantially greater than the highest price expectations on which such investments have been based. Many of the areas in which group A deposits are located have such high operating costs that they have received only a cursory analysis of their resource potential. Yet precisely because of their high costs, application of the rule for the sequencing of development conserves the resources of these areas for future generations. However, owing to the shortage of reliable information about the extent and location of these resources, they do not greatly influence the planning of future exploration and development. Since the extent of the resource saved for future consumption is not evident, the concern about conserving acreage for the future focuses on currently economic resources.

If the information needed for the idealized inventory were costless to acquire, then there would be no reason not to compile a perfect inventory and manage development accordingly. Unfortunately, the advantages gained from a perfect inventory are not likely to exceed the very substantial costs of getting one. Thus, given the substantial cost of investments in seismic evaluation and exploratory drilling, it is appropriate to seek a sequencing rule under certainty that parallels the sequencing rule set forth earlier for investments necessary to bring known deposits into production. It is not difficult to show that, assuming independence among prospects, the optimal sequencing rule in the presence of uncertainty is directly analogous to the case of certainity. To maximize the long-term average economic benefit, investments should be ordered with reference to current and future expected (average) net economic benefits.

Expected value is the economist's term for an estimate that reflects both the values of all the possible outcomes of an investment and their probabilities. Since experience in the search for oil and gas deposits generally allows analysts to characterize the outcomes and probabilities for a given prospect, its value can be expressed as an expected value.

A simple example is useful to illustrate the calculation of expected value. The flip of a silver dollar has a 50-percent chance of coming up heads and 50-percent chance of coming up tails. If the dollar is won on heads and nothing lost on tails, then the expected value of the flip is \$0.50 (0.5 x \$1.00 + 0.5 x \$0.00).

For prospects that have been identified, it is possible, though still costly, to estimate their expected value. Such estimates can reflect the possible outcomes and their probabilities for all key parameters on which value depends, including future prices and costs, the resource's geologic magnitudes and risks, and the discount rate.

The choice of a discount rate to use in estimating the economic value of offshore oil and gas resources is an issue on which economists have not reached a consensus. Comments on the proposed 5-year program include the contention that the energy industry's cost of capital is greater than that of the Government's cost of capital, and that the eight percent (public) discount rate used in the analysis is too high.

The common assumption is that the correct discount (interest) rate is the social rate of time preference, which reflects how society as a whole weighs the tradeoffs between present and future consumption. Two fundamental aspects of the way in which time affects resource values are captured by this discount rate: first, the way in which society values economic productivity in the short run (say, the next 5 to 10 years) as compared to economic productivity in the long run (say 10 to 50 years) and second, the returns inherent to the gains in future economic productivity that are expected from other investment opportunities. In general, the more the American people are willing to give up consumption in the short run in order to have greater consumption in the long run, the lower will be the discount rate. One would not have to pay very high interest rates to achieve high savings rates in this situation. On the other hand, the greater the returns from other investment opportunities, the higher will be the discount rate. Firms will be willing to borrow at higher interest rates because their investments yield higher returns.

Since financial markets work to bring savings and investment into equilibrium, the ideal discount rate is the interest rate that would be observed in well-functioning financial markets. Interest rates can be thought of as the price of capital. As in any market, the price will be determined by the interaction of supply and demand.

The supply of capital arises from individual members of society. Out of each dollar of income, each individual allocates a certain proportion for immediate consumption, and the rest is saved. The amount saved depends on a number of factors, including: current and expected future income, current and expected future consumption needs and desires, the level of each individual's concern for the welfare of his children, and the nature of savings opportunities, available now and in the future. The result is the supply of capital.

Demand for capital depends on the range of investment opportunities. For an individual, the demand for capital is derived from the same factors discussed above, but his decision is, in effect, negative saving--borrowing against future income for current consumption. A corporation will look for opportunities that will provide a rate of return at least as high as the cost of the capital employed. The investor's view of investment oportunities depends on his perception of present and future economic growth, technological progress, distribution of wealth, and consumer preferences, among others.

The discount rate results from the equilibrium between savings and investment. A combination of a high level of savings and a low demand for investment capital will lead to a low discount rate. People's preference to save for future consumption will result in less present consumption in general and less energy consumption in particular. The OCS will be developed at a slower pace by our idealized manager because fewer deposits have benefits growing slower than the discount rate, given a rate of price increase. Strong demand for capital combined with a low level of savings will result in a high discount rate. The pace of OCS development will quicken because the manager will have a greater number of deposits with benefits growing slower than the discount rate. Other combinations of savings and investment demand will lead to a development pace between those of the two examples.

Unfortunately, there is not a single equilibrium interest rate in the economy. The interest rates that can be observed in the market are the rate of return on capital and the consumer's rate of interest. The former is the minimum rate of return required by an investor to undertake a project, or the interest rate cost of the capital employed in the project. The consumer's rate of interest reflects how individuals decide between consumption and saving, and is revealed by the interest rates at which consumers can borrow or save money. The problem is to decide which, if any, of these observable interest rates best approximates the social rate of time perference.

In the ideal world of economic theory, all of these interest rates are identical. Actual capital markets, however, contain a number of imperfections that cause the various interest rates to diverge from each other. The problems that are easiest to deal with are inflation and taxation. It is generally agreed that for the purpose of evaluating incremental project alternatives, the discount rates should be real, after-tax rates. Other problems, only some of which will be mentioned below, do not allow such straightforward adjustments.

First, observed market rates of interest are distorted if markets are not in perfect equilibrium. The presence of unemployment, for example, indicates that markets are not functioning perfectly, and therefore that observed quantities, like prices and interest rates, are not at their ideal level. Second, some benefits and costs, such as information benefits and environmental costs, are not captured in market transactions, so market prices do not reflect actual social values. Third, the Government may directly influence the level of interest rates in the market through fiscal and monetary policies and create industry-to-industry variations in the rates of return through regulatory and tax policies.

Another source of variation in observed rates of interest is risk. The rate of return earned by investors usually increases with the amount of risk inherent in the project. This has led some economists to propose that the Government should use the discount rate that is employed by the private sector in considering projects of similar risk. In the case of OCS development, the Government would use the same discount rate that the energy industry employs. Other economists argue that the government benefits from risk-pooling,

in which the government's investment portfolio is so large that the incremental risk from one additional investment is negligible, and risk is spread over the entire population so that the risk to any member of society of negligible. This argument suggests that the government should employ a discount rate that does not incorporate risk.

Finally, it has been argued that capital markets do not appropriately reflect the preferences of future generations. Some economists contend that a lower discount rate should be used because individuals systematically undervalue the consumption of future generations. People give greater weight to the consumption of contemporaries and immediate descendants than they do to the consumption of more distant future generations. Even if this were not the case, the interest rates observed in the market reflect only individual's preferences with respect to their own consumption. Individuals as members of society would choose a discount rate lower than the rate they choose as consumers.

Other economists argue that the welfare of future generations may be better off than the present generation, thus, not requiring an exogenously determined lower discount rate than those observed in the market. For example, Joseph Stiglitz states:

> One should not view equity in a narrow sense of simply looking at the division of natural resources between present and future generations; the present generation may give future generations fewer natural resources (this is inevitable in the case of exhaustible natural resources), but it will give future generations a higher level of technology and more capital. One has to look at the relative welfare of the different generations and there is a strong presumption that future generations may be better off than the present generation. On grounds of equity it might be argued that we should consume even more now (including more natural resources). (J.E. Stiglitz, 1979, "A Neoclassical Analysis of the Economics of Natural Resources," in V.K. Smith, ed., Scarcity and Growth Reconsidered, Baltimore: John Hopkins University Press, p. 61).

All of the preceding factors cause market interest rates to diverge from each other and from the ideal social discount rate. Individually, these factors can drive observed interest rates either above or below the social rate of time preference. As a group, their net effect is unclear, and the relationship between market rates of interest and the social discount rate is not well defined. (For a more complete review of the discount rate issue, see Robert Lind, et. al., 1982, Discounting for Time and Risk in Energy Policy, Baltimore: Johns Hopkins University Press).

Comments have been suggested that an appropriate rate of discount is the interest rate on Government bonds because this rate represents the opportunity cost to the Government of raising funds. This argument presumes that there is a one-to-one correspondence between Federal OCS revenues and Government borrowing. In other words, every dollar of Federal OCS revenue replaces exactly one dollar that the Treasury would otherwise have borrowed. If this were the case, the interest rate on Government bonds would be the correct discount rate for analyzing the revenue effects of OCS leasing.

It does not appear, however, that a one-to-one correspondence exists. If OCS revenues were to decline, the Government might choose to increase taxes and reduce spending in addition to an increase in borrowing. These alternatives would have attendant and different effects on the economy. Taxation alters the consumption and investment patterns to a degree that depends on both the distribution of the tax burden and the distortional incentives on spending. Government expenditures can be targeted both toward current consumption and social investments with future payoffs.

To the extent that Federal OCS revenues offset taxes or augment expenditures, the discount rate used to analyze the revenues must reflect the interest rates that are inherent in the consumption and investment effects in the economy. The interest rates or opportunity costs associated with these activities are higher than the rate on Government bonds. Thus, a social discount rate chosen solely on the basis of Government borrowing would be too low. (Recent real rates of interest on long term Government bonds have been in the 6- to 8-percent range.)

In deciding upon the proper discount rate to use in managing the OCS program, it must be recognized that the decision variables (e.g., leasing rate, sale size, sale locations, etc.) do not mandate the displacement of private consumption or investment with public funding. Hence, unlike a decision to build a highway or dam, the decisions for an OCS program that lead to capital investments are undertaken voluntarily by the private energy sector. Moreover, one would expect that the rate of return available on a government sponsored project with risk equal to that in the energy sector would correspond to the real after-tax return that applies in that sector. Thus, it might be argued that a reasonable yardstick with which to measure time-dependent cash flows for OCS projects is the real after-tax discount rate that applied in the energy industry.

A recent survey of the 19 largest U.S. oil and gas producers revealed that they used an average real after-tax discount rate of 7 percent. (H. Royle and G. Schenk, 1985, "Investment Analysis: U.S. Oil and Gas Producers Score High in University Survey," Journal of Petroleum Technology, Vol. 37, No. 4.) Another evaluation of the industry opportunity cost of capital resulted in the measurement of after-tax rates of return on OCS investments in the Gulf of Mexico. (W. Mead et. al., 1980, Studies of Competition and Performance in OCS Oil and Gas Sales, 1954-1975, Final Report, USGS Contract No. 14-08-0001-18678.) The study concluded that companies earned a nominal after-tax rate of about 9 percent, during a period in which inflation was averaging about 2 percent. The nominal rate adjusted for inflation, i.e., the real rate, was therefore about 7 percent.

In light of the foregoing discussion, the analysis in this program document employs a range of discount rates between 6- to 8-percent. Nevertheless, it should be recognized that in considering the social welfare associated with the OCS program, the choice of discount rates is an ethical as well as economic one, and a society's ethics may best be captured through the political process. Any decision to alter the discount rate used to evaluate OCS offerings therefore implies a political decision to modify the pace of leasing both within and among the defined planning areas.

In principle, an economically beneficial path of investment in the search for, as well as the development of, OCS oil and gas deposits could be achieved by taking each step in the investment process for each prospect at the time when, given expected oil prices and costs, the expected value of that step would no longer be increased by a delay in development at a rate that exceeds the discount rate. Although this rule reflects uncertainty about oil and gas deposits and prices and costs, it does not reflect the institutional arrangements and processes by which the Federal Government and private firms bring about OCS investments: the Department of the Interior's leasing program and lease sale procedures, combined with the investment processes that occur in the private sector.

A major advantage of the private investment process is the linking of actual investments to the payoffs as seen by the investors. The actual path of investment in OCS oil and gas results not from the inventory and data compiled by a single organization such as a Government Agency, but from efforts by a diverse set of firms working to identify oil and gas prospects that warrant investment. This diversity helps to reduce the "blindness" that could result from a more monolithic approach, increasing the chances that worthwhile prospects will be identified in a timely manner. It also makes the actual investments voluntary rather than coercive as they would be if made or commanded by a governmental agency. Thus, the Government cannot force investments to go forward; however, it can prevent them from occurring by not making acreage available when firms are ready to invest in it. Similarly, in formulating a leasing program based, in part, on Government estimates, it is reasonable to allow for the fact that firms who are considering acquisition and exploration investments may have significantly different estimates for a given area. The next section elaborates on the possible structures of the leasing program and lease sale procedures and discusses their relationship to the investment decisions made by the petroleum firms engaged in OCS exploration and development.

Generally speaking, private sector investment decisions could be relied upon to give efficiently timed investments in OCS oil and gas deposits if markets were perfectly competitive and free of distortions. In such markets, prices accurately reflect social costs. As commenters on the Draft Proposed Program pointed out, the existence of numerous market imperfections makes it unlikely that private investment decisions will yield the optimum investment path of the idealized model. The important market inperfections identified by these commenters include tax policies, price controls, and externalities such as

environmental costs and common information. The existence of market power due to lack of competition in an extractive industry is also a possible market imperfection. It is possible to determine the general effects of such imperfections taken individually. Some, such as taxes, royalties, price controls that depress prices, and market power would tend to slow investments in OCS deposits. Others, such as environmental externalities, tend to yield private investments at times earlier (in periods of increasing resource prices) than is best for society. While the economics literature contains a variety of theoretical analyses of such effects, both individually and in limited combinations, neither the comments nor the literature provide a systematic treatment of all market imperfections. While one commenter recommends a "carefully controlled and designed leasing program . . . to ensure economic efficiency," there are no currently available methods for analyzing the many possible market imperfections and determining how to "control" leasing so as to fully correct for their effects.

Furthermore, given the uncertainty as to the size and location of individual unleased deposits, it does not seem reasonable to design a leasing program that would control the timing of investments on each prospect in light of the effects of market inperfections on private investment decisions. While the Government has the same resource data on unleased OCS oil and gas prospects as do firms, interpretations of those data vary widely. Prior to exploratory drilling, it is not possible to say whether an optimistic or pessimistic assessment of a given prospect is correct. Thus, when a firm is willing to invest in exploration of a prospect while the Government concludes that it is not yet an opportune time for investment, it is not possible for anyone to determine whether the firm's interest reflects market imperfections that would yield premature investment or a possibly correct judgment that the prospect will yield a great enough return to warrant investment. It is thus reasonable to observe that even if the effects of actual market imperfections were well known, a leasing program that attempted to control the timing of investments on the basis solely of the Government's prospect by prospect resource evaluation would be unlikely to yield efficiently timed investments in exploration and development. On the other hand, a policy that would control the timing of investments, correcting for any tendency for premature private investment without relying solely upon the Government's assessment of individual prospects could be a desirable feature of the leasing program.

In areas of proven hydrocarbon occurrence or high industry interest, there may by a tendency for lessees to acquire, explore, and develop prospects sooner than is socially desirable. This situation has greater efficiency implications in areawide sales because more reliance is placed on the private market in making prospect-specific leasing decisions.

An important underlying condition that is associated with the problem of premature leasing is the tendency for exhaustible resource deposits, such as oil and gas, to rise in real value over time. This means that the leasing and subsequent development scenario which is best for the Nation may involve a delay in the sale of high cost prospects in a planning area even while investments are proceeding on lower cost prospects. Absent some mechanism to prevent the leasing of prospects, tracts with positive private value could be leased and subsequently developed too soon, partly because of diligence requirements. Ideally, these prospects should be retained in the Government's

inventory until the time when their sale would produce maximum net benefits to the Nation. Moreover, if private after-tax discount rates exceed the government's cost of borrowing, then the present value of cash bonus receipts could be enhanced by delaying the sale of certain types of tracts which industry might otherwise want to acquire. A policy instrument which can be employed to filter for leasing the "right" set of tracts is the minimum bid.

Establishing an appropriate minimum bid based on a standard for the best timing of lease acquisition and subsequent exploration requires an analysis and comparison of the factors that comprise public value (i.e., net economic value (NEV)) and private value (i.e., after-tax net present value (ATNPV)). The factors affecting these two values vary from OCS planning area to planning area and cost regime to cost regime. From the standpoint of economic efficiency, a tract should be leased if its NEV as developed today is greater than if developed in all future periods. Conversely, leasing of tracts should be delayed if the NEV is higher if developed in some future period.

A model has been designed to analyze the appropriate size of the minimum bid under different economic conditions. This model is described in a paper titled: Analysis of Minimum Bid Policies, Branch of Economic Studies, Offshore Resource Evaluation Division, June 7, 1985. It includes an example to demonstrate how the minimum bid can be computed to achieve the objective of appropriate timing for the sale of prospects in a given planning area/water depth.

The model was also employed to evaluate the effects on the smallest field size that should be leased at a given time, and on the size of the minimum bid that should apply at that time, in the presence of changes in existing geologic and economic factors. This analysis was carried out by computing the change in the smallest sized field to be leased, evaluating the ATNPV associated with this new field size under the revised conditions, and comparing the new ATNPV to the original ATNPV.

The analysis found that on a prospect-specific basis, an increase in either the price of oil and gas or the rate of production has the effect of reducing the minimum bid that is appropriate for the best timing of leasing. On the other hand, an increase in the costs of exploration, development, and production leads to an increase in the appropriate level of the minimum bid.* This

*These results occur because an increase in the economic value of the resources tends to lower the size of the smallest prospect that should be leased at a given time, i.e., some smaller prospects have now matured sufficiently in value to justify current leasing. The revised private value of this smallest leasable prospect is generally lower than the private value of the original smallest prospect that previously was appropriate to lease, so the minimum bid needs to be lowered as well. An important exception occurs in the case of the prospect success rate. As before, an increase in the likelihood of success raises the economic value of the resources and hence lowers the size of the minimum leasable prospect. However, the revised private value of this smaller prospect is generally raised compared to the previously sized smallest leasable prospect, so the minimum bid increases too.

finding is at odds with arguments that conclude that in high-cost areas, the minimum bid should be reduced to encourage bidding. That argument is based on the premise that it is desirable to help stimulate bidding interest in marginal areas. However, based on economic efficiency, encouraging bidding in high-cost areas is not desirable, per se. Other factors being equal, high-cost areas (and high-cost prospects in a given area) should tend to be developed later. This is the pattern developed by the competitive market as evidenced by the development history of both onshore and offshore areas, and is consistent with the sequencing rules discussed earlier for the idealized manager.

In high-risk areas there is usually a high degree of dependence among prospects. This is especially true for unproven areas where the existence of commercial accumulations of hydrocarbons has not been demonstrated. In these cases, the information generated by an exploration program on a given prospect may improve the efficiency of future drilling patterns for much of the surrounding acreage, regardless of whether the specific prospect is hydrocarbon prone or not. However, unless the leaseholder has acquired this informationally related acreage, he will not be able to capture the full value of the benefits that emerge from his exploration program. Also, if companies exhibit risk averse behavior, they will value tracts in frontier areas relatively less than tracts in proven areas. Accordingly, because of these two effects, there will be a tendency for the private market to relatively undervalue and hence lease less acreage in frontier areas vis-a-vis proven areas. To account for these affects, it is appropriate to consider lower minimum bids in high risk areas.

Thus, we see that the desirability of encouraging exploration in high-risk/high-cost areas stems from the information benefits that are imperfectly captured by individual firms. The high basin risk and the attendant information gained from society's perspective in these areas argue for a lower minimum bid, while the high-costs argue for a higher minimum bid. Which one of these countervailing tendencies predominates determines whether or not the minimum bid should be lower or higher.

Unfortunately, interdependence between prospects results in analytical complications that make it difficult to obtain precise results for the minimum bid level in frontier areas. This is primarily the case because of the difficulty in quantifying the geological and economic dependence among prospects, and the information externalities that could emerge. However, since we know that the effect of prospect dependence is to reduce the minimum bid, the minimum bid model can be applied to frontier areas by assuming that prospects are independent, the resulting minimum bid is then interpreted as an upper bound, and no more precise specification based on the timing of leasing criterion may be possible.

D. Guidelines for Leasing Program Formulation

The general principles for sequencing the investments in OCS oil and gas and the various possible distributions of resources across the range of net economic values for each planning area can be used to develop a set of economic guidelines for formulating a leasing program. These guidelines can then be modified to incorporate noneconomic considerations as required by section 18 of the OCSLA.

In developing such guidelines, it was necessary to recognize the difference between management of the Federal leasing program and the idealized management of OCS investments discussed above. The leasing program cannot cause investments to be made, as the idealized manager could, when they are judged to be optimal. Instead, the leasing program can make available to private firms certain prospects at an appropriate time. Actual investments in the prospects made available result when such firms find them more attractive than other investment opportunities available to them. Furthermore, the Secretary, in formulating the leasing program, is confronted by substantial uncertainty as to the actual and perceived conditions under which these private firms will make their investment decisions. This places limits on the information relating to resources and economic values which the Secretary has available for consideration. It is not possible to predict with much accuracy or precision what the state of geological knowledge, technology, and price expectations in the period starting in 1987 will be. Thus, the guidelines developed for formulating a leasing program must provide for flexibility in the program so that OCS prospects can be made available in an economically appropriate way under a wide range of future conditions.

The estimates of resources and net economic values in the OCS planning areas provide both the totals for leasable resources and net economic value and the distribution of resources across the range of net economic value per barrel from moderately uneconomical to about $10 per barrel. Section VI discusses these in detail. An idealized OCS manager might ignore the area boundaries and schedule investments by working from the most valuable prospects per barrel down to those just becoming timely for investment. Appropriate economic guidelines for a leasing program can be derived by identifying ways to approximate this sequence through area-by-area lease sales. Thus, based on economic guidelines, lease sales should generally occur earliest in areas with the highest valued prospects per barrel and most frequently in areas with the largest amount of aggregate net economic value. At the other end of the spectrum, areas with no resources having positive economic value, even under the highest price projections, should be offered for leasing last, if at all, during the 5-year period.

In developing a guideline to offer the best areas earliest and most frequently, it is reasonable to consider the effects of delays in leasing and investment. Even in the "best" areas (i.e., those having the largest stock of potentially recoverable resources), there are high-cost and low-cost prospects. The low-cost prospects have high net economic value per barrel and would yield less benefit, losing in present value, if leasing and investment were delayed even while prices increased. The high-cost prospects have low net economic value per barrel and could gain more value from delay than they would yield in the present economy. For the better areas, the prospects that would lose from not leasing outweigh the prospects that would gain from delay. Such a delay in leasing would be a loss to the economy, on balance, in such areas. Moreover, the economic terms of OCS leases along with income tax considerations tend to discourage the acquisition of prospects that would gain from delay. Such prospects tend not to be leasable because royalty and tax payments make them less valuable to a lessee than they are to the nation. This makes it

possible to offer areas with many prospects that could gain in benefits if investments were delayed, with some confidence that premature investments will not be made to any substantial extent. When minimum bids are fine-tuned to enhance intertemporal rates of lease acquisition, the likelihood of premature leasing is further reduced.

For areas that fall in the range between the best areas and the worst areas, development of scheduling guidelines is less obvious. Nevertheless, a reasonable approach begins by determining the conditions under which an area with apparently little resources or economic value should be offered during the 5-year program. One reason to offer a marginal area is that the area may contain more resources than we think it does, perhaps as suggested by industry interest. Another reason is the possibility that a future price increase could very substantially increase the recoverable amount and net economic value of resources in that area. This possibility results from a distribution of resources in which a substantial amount of resources fall in the range just below the "minimum leasable value." Higher prices would shift all deposits to higher net economic value, making more resources beneficial to find and produce. One way to treat such areas is by scheduling tentative sales which could be held if conditions more favorable to leasing materialize. Estimates of the additional "leasable" resources (i.e., resources having a positive private value) and net economic value resulting from substantially higher prices can help to identify such areas.

Areas with relatively low estimates of leasable resources are worth offering at least once if their net economic value is likely to exceed the external costs plus the administrative costs of holding a lease sale. Furthermore, in many areas, low resource estimates have been based on relatively little geologic and geophysical data. In deciding whether to include low resource areas in the 5-year program, one consideration is the possibility that the firms gathering additional data for their presale evaluations in the area will identify leasable prospects not included in the current MMS estimates. A decision not to offer a marginal area reduces the likelihood of this possibility. In addition, the classification of resources in categories such as high, moderate, or low is subjective and is based on risked mean recoverable resource estimates. Considerable uncertainty and ranges exist in the estimates, therefore they should not be considered exact.

There are a number of areas of moderate resource potential for which the formulation of a leasing program needs to resolve questions of priority and frequency. In general, areas having about the same resource potential should be offered in order of their net economic value. This will tend to allow investments in higher valued resources to occur earlier and will minimize any possibility of premature investments in marginally valued prospects. If areas have about the same aggregate net economic value, but significantly different resource potential, then economic efficiency argues for offering the area with <u>less</u> resources first, because they would have lower costs. Once again, this criterion encourages leasing and hence investment in the highest valued prospects. The set of investments made on the better prospects in that area will have greater expected returns than the set of investments in the area with fewer high value prospects.

A further guideline for establishing priority among similar areas is the extent of previous drilling. The early exploratory wells in a frontier area give strong indications of whether there are hydrocarbons in the area even if they do not yield commercial discoveries. Until such indications are confirmed, the area must be regarded as having a relatively low probability of hydrocarbon presence. This low probability results in low estimates of risked leasable resources and expected net economic value even if the volumes of identified prospects are substantial. By comparison, an area with a much higher probability of hydrocarbons because of previous drilling could have similar risked resources and net economic value from fewer prospects. As a result, drilling in the unexplored area can yield information that could more significantly change the estimates on which subsequent investments will be based. Thus, it is generally preferable to offer unexplored areas first, when risked resources and economic values are similar.

VI. OCS Resources and Net Economic Value Estimates: Considerations for Leasing and Program Formulation

A. Introduction

The analysis of resource potential and net economic value in each OCS planning area was designed to help the Secretary consider the potential for discovery of oil and gas in each of the areas and the contribution such discoveries can make toward meeting the Nation's economic and energy needs. It was also designed to facilitate the analysis of the external costs that might result from the exploration, development, and production of the resources in each area. This section provides a detailed description of the investment process and the way in which the economic benefits were estimated for the potential oil and gas discoveries which they may yield.

Two fundamental problems are confronted in estimating the oil and gas resources and the economic value for OCS planning areas. The first is the inherent uncertainty about the results of each step in the investment process. Because little is known about the location and size of oil and gas deposits until actual investments in exploration have been made, the results can vary from highly negative to highly positive with regard to the initiation of each subsequent step in the development process. Resource and economic value estimates need to reflect these chance outcomes.

The second problem encountered is the incorporation of investment decisions and the possible economic conditions under which they will be made into the economic value estimates. Hydrocarbon-bearing areas contain more oil and gas than will be recovered under the economic conditions that prevail in the period relevant to formulation of the leasing program. The resource and economic value estimates considered by the Secretary need to show how the potential for discovery of oil and gas and the economic benefits realized from their production are affected by economic conditions.

This section discusses how the two problems mentioned above are dealt with in estimating oil and gas resources and net economic value for OCS planning areas. Next, a series of measures of resources and economic values are presented for each planning area. The section concludes with a discussion of the relationship between the data presented and generation of the appropriate parameters of a leasing schedule.

B. Stages in OCS Investment Decisions

The series of investment decisions leading to the production of oil and gas that can meet national energy and economic needs is essentially structured according to the operational steps required to bring a lease to production. The following discussion highlights the types of operational activities occurring during each step in the process:

1. Prelease Evaluation

Firms invest in geological and geophysical data and evaluation to identify and assess individual prospects for discovery of oil and gas. Undiscovered resource estimates are made by identifying areas of resource potential on the basis of broad geologic knowledge and theory. Until a well has been drilled, investigators derive all their knowledge of subsurface geology indirectly from geologic and geophysical (seismic) data collected at the surface. Using available data as a basis for further investigations, petroleum geologists then conduct a variety of geologic assessments of the region. The geologists' data base may include physical confirmation of the presence of resources by actual drilling in an area that has been previously leased. Under prelease permits, geophysical surveys (seismic data), shallow coring, and deep stratigraphic tests (drilling) may be done. This is generally completed before a lease sale. The knowledge gained from these geological and geophysical analyses are used to highlight prospective areas and to determine which tracts to bid on and how much to bid at a lease sale.

2. Leasing

Firms invest in the acquisition of oil and gas rights through competitive bidding. The primary terms of the lease involve financial considerations in the form of future payments to the Government, and stipulations requiring that specific milestones and tasks be met by the lessee in order to retain the rights to the lease.

3. Exploratory Drilling

Following a lease sale, the initial phase of offshore oil and gas operations, known as exploratory drilling, begins. Firms invest in drilling of prospects on tracts they have leased to determine the presence and extent of oil and gas; most prospects contain no oil and gas.

Exploration is generally completed within 5 years of the date of issuance of a lease; 5 years is the length of the primary term of leases set by law unless certain specific conditions exist. Once a tract has been leased, geological, cultural, and biological surveys are conducted to develop a comprehensive exploration plan. The operator cannot begin exploratory drilling until an exploration plan has been approved for the lease and an application for permit to drill (APD) a well has been submitted and approved. Obtaining these approvals also entails obtaining permits or approvals from other agencies, such as State Coastal Zone Management consistency certification and EPA NPDES permits. For leases issued with an initial period of 5 years, an exploration plan or a statement of exploration intentions must be submitted by the end of the fourth lease year. The time period for submittal on leases with longer primary terms (such as 8- or 10-year leases) must be specified at the time of leasing. The exploration plan and APD provide a concise description of the proposed offshore operations including specific information on the location and depth of wells. Revisions must be submitted and approved for any significant changes.

When exploration begins, operators select one of several types of drilling rigs to match water depth, drilling depth, and bottom conditions. The offshore exploration activity is supported by onshore bases from which supplies are transported to the drilling rig. Apart from these supply bases, little onshore development generally takes place during the exploration phase.

4. Delineation and Development

The delineation and development phase encompasses the activities necessary to bring a discovered field to the point of commercial production. This is a period of intense activity. Firms invest in the installation of production platforms, wells, pipelines, and equipment used to recover oil and gas. When significant quantities of hydrocarbons are discovered, delineation wells are drilled to determine the field's configurations and capacity.

Most of the critical decisions concerning the location and construction of onshore and offshore facilities are made during the development phase. An OCS operator prepares for the production phase through development activities which include extensive planning, submission, and approval of plans of development and production (POD/P), installation of platforms and pipelines, and development drilling. The onshore facilities required to support development activities may include permanent service bases, repair and maintenance yards, storage and treatment plants, and marine terminals. In mature areas such as the Central and Western Gulf of Mexico planning areas, in comparison to frontier areas, impacts are lessened because this infrastructure has already been adequately developed to handle most of the demand. Here, economies of scale can be realized as costs are lower because only incremental expansion of offshore production and pipeline facilities and onshore support and processing facilities are necessary. Early developers in frontier areas must at least initially bear all such costs.

Completion is the term used to encompass the various activities necessary to convert a well into a producer of oil and/or gas. It may involve setting and cementing casing; perforating the casing to permit oil and gas to flow into the wellhole; fracturing; acidizing; consolidating sand; setting tubing; and installing downhole safety devices. Deepwater wells (800 to 1,000 feet of water), drilled and produced from sophisticated platforms, are becoming more common. Subsea completions for even deeper water are available but are being used more worldwide than offshore United States. These are wells in which the major assembly of piping, valves, and related equipment used to produce oil and gas are located at or near the sea bottom. The wellhead is placed on the sea floor rather than on platforms, and the produced liquids or gases are transferred from the wellhead either to the nearby platform or directly to a shore facility.

5. Production

In the production phase, oil and gas are produced from offshore wells. Hydrocarbons are normally transported to shore in the pipelines laid during the development phase; otherwise, they are transported by tankers or barges. Production has the longest duration of all phases of offshore operations related to a specific prospect. It may last for 20 to 30 years. Characteristically, employment offshore drops sharply from that of the development stage as production becomes routine. In addition, some platforms are automated and require only daily inspections and regular maintenance. The process of bringing new fields into full production requires additional drilling and labor. Until each new field is defined, exploration and development drilling in the form of delineation will continue. When production declines, wells are periodically worked over to boost output.

C. Resource Recovery and Economic Conditions

In formulating a leasing program, it is reasonable for the Secretary to consider how much hydrocarbons in each OCS planning area will be found and recovered. Such estimates need to reflect the economic behavior of the many firms making the investment decisions by which resources are expected to be leased, explored, discovered, developed into proven reserves, and produced. Given estimated prices and costs, these economic decisions may result in leaving some of the oil and gas that is actually in place unrecovered for a variety of reasons, including:

- those in geological features that are not "visible" in the geological and geophysical data on which bidding and exploratory drilling are based.
- those in prospects not worth bidding upon.
- those in prospects that get leased but are judged not to be worth drilling.
- those in drilled prospects that are missed.
- oil and gas deposits that are found by exploratory drilling but which are not worth developing.
- oil and gas in place in discoveries that are developed but which are not worth recovering.

The bidding, exploration, development, and recovery decisions that yield these results depend, to an important extent, on economic conditions. Since prices and costs change over time, oil and gas that would not be found and produced during one period in time may later become economic, particularly if the ratio of prices to costs increase. Most resource estimating methods include general assumptions about the portion of oil or gas in a discovered deposit that is economically recoverable, primarily relying upon past experience

to set the percentage recovery. Similarly, most methods reflect the condition that deposits below a certain size have been uneconomic.

Unfortunately, most resource estimates do not reflect the increases in the percentage recovery that may result at higher oil prices. Similarly, most resource estimates have not been precise in the use of the concept of minimum economic field size. The resource estimates developed for the formulation of the 5-year leasing program, however, emerged from methods that are able to show the effect of changing economic conditions on the resources that are economic at various steps in the investment process for those prospects that have been identified as containing at least some economically recoverable resources at current and expected future prices.

Given the costs of drilling operations, platform construction and installation, transportation in a particular area, and expectations about future prices, the primary determinant of whether or not the oil and gas in a particular unexplored prospect or discovered deposit is recoverable is the amount of oil and gas it contains. Because some investments are not easily divisible (for example, it's not possible to drill half a well), the minimum lump sum investment can overwhelm the production revenues from a small deposit. Thus, for each level of costs, there is a minimum economic prospect or field size that is equal to the next lump sum of investment. There is a minimum size that is worth leasing, given the geologic risk, the minimum bid, and other economic terms of the lease. There is similarly a minimum size that is worth the initial lump sum of investment in development given that the deposit has already been found. For given price expectations and geologic risk, the higher the costs, the larger such minimums will be, and the greater the size and number of uneconomic prospects and deposits in an area.

The unleased, undiscovered oil and gas existing in an OCS planning area at a given point in time is distributed among a population of prospects of various sizes and locations. The conditional resource sizes of these prospects and their geologic risks are dependent upon the information available to make such estimates. As such, it is not surprising to find little data on prospects that are not economical to produce because they are too small and/or too costly under current and expected future economic conditions. Thus, while sophisticated models are capable of evaluating the sensitivity of production for the identified fields for myriad assumptions regarding economic parameters, it must be recognized that the set of identified prospects is, by necessity, "limited" to those having at least some chance (i.e., 1 in 5,000) of being economical to produce under the base case economic scenario.

The uncertainties associated with the overall presence of oil and gas in an area and about the key parameters affecting individual prospects are incorporated into resource estimating methods. Estimates that assume the existence of oil and gas in an area are called conditional resource estimates. Conditional resource estimates are good indicators of the oil and gas production that could result from successful investments in various OCS areas. They reflect the recoverable resources that could be contained by the volumes of oil and gas bearing rock estimated to be present in the area. They do not reflect the likelihood that oil and gas is, in fact, trapped in those volumes.

Conditional resource estimates are most useful in assessing the environmental impacts that might result from oil and gas exploration, development, and production activities.

Conditional resource estimates, however, substantially overstate the results of exploration in the OCS as a whole, just as assuming every lottery ticket was a winner would overstate the total prize money of a lottery. The potential for oil and gas discovery in an area depends upon the chances of finding oil and gas, as well as the volumes of reservoir rock that can contain oil and gas. For areas with no previous discoveries, the probabilities are substantially less than 100 percent. Thus, it is appropriate to consider estimates that reflect the probability that oil and gas are present in the area. Risked resource estimates (which take into account the probability of hydrocarbon occurrence) reflect those probabilities. Expected net economic value estimates are based on risked resource estimates.

D. Resource Estimates and Economic Values

Traditional economic analysis, usually in the form of cost-benefit studies, focuses on the sum of consumer and producer surplus as the principal criterion of a program's efficiency. Consumer surplus measures the difference between the amount that users or purchasers of a good or service would be willing to pay and the amount they are required to pay at the market-clearing equilibrium price. Producer surplus typically measures the difference between the revenue received by the seller (producer) of the good or service and the opportunity cost of producing it.

Because the OCS market represents only a small portion of the world's petroleum market, and because this market is highly influenced by the production and reserves of OPEC countries, it is reasonable to assume that alternative OCS policies and resulting production rates will have a negligible effect on the world price of oil. Because of this, we have a situation in which incremental OCS production simply substitutes for the highest cost alternative source of petroleum currently being sold in the U.S. market, i.e., imported oil.

As long as OCS production has little or no effect on the market price of oil, it also does not directly benefit the ultimate consumers of petroleum. Thus, the analysis of benefits and costs can focus on benefits accruing from the production of the resource without addressing changes in consumer surplus. Measurement of benefits derived from oil and gas price changes induced by OCS production was discussed earlier in the section dealing with import premia.

In the case of the OCS, where the assets represented by potential oil and gas deposits are owned by the U.S. Government and subsequently leased to private industry for ultimate extraction, producer surplus represents the difference between the market value of expected production and the real resource cost of exploring, developing, producing, and transporting the expected production to market. This economic rent, or net economic value, will be distributed between the lessor (U.S. Government) and the lessees (private firms), depending

upon the relative amount of transfer payments which the Government collects in the form of cash bonuses, rentals, royalties, windfall profits taxes, and corporate income taxes. The remainder of the net economic value is retained by private industry in the form of economic (as opposed to accounting) profits.

Assuming the absence of capital constraints and employing a reasonable opportunity cost of capital for the discount rate, the resulting measure of net economic value will simultaneously represent the improvement in national income to the country from a specified OCS investment alternative, as well as the total of the resulting transfer payments and corporate profits. Even if investment opportunities are constrained by capital shortages, establishment of an appropriate (marginal) opportunity cost of capital will result in a realistic and, insofar as possible, accurate estimate of the incremental improvement in net economic value and the related transfer payments.

While the vast majority of benefits generated by an OCS schedule can be measured by net economic value, as discussed previously, there are other less important but not insignificant benefits. First is the potential savings on the size of the Strategic Petroleum Reserve as OCS production replaces imports. Even if no change in the Strategic Petroleum Reserve is forthcoming, the given size of the inventory will afford a higher level of protection as imports decline.

Other benefits of OCS production include incentives for OPEC to lower prices, increased national security, improvements in our balance of trade, and reductions in the budget deficit. While no attempt is made to quantify these additional benefits, their presence and potential magnitude suggest that the net economic value estimates, even as large as they are, represent a rather conservative measure of the benefits of the OCS program.

The MMS has estimated the undiscovered economically recoverable oil and gas resources expected to be unleased as of January 1987 (see Table 6) and net economic value in the various OCS planning areas. These estimates of necessity reflect the state of geological and geophysical knowledge and expectations of the relevant future economic conditions at the time the estimates were made (see section VII). They were based on an early 1987 starting point for the next 5-year leasing program. The resulting estimates of unleased, undiscovered, economically recoverable oil and gas resources reflect geological and geophysical knowledge as of the first quarter of 1985 and contemporary projections of economic conditions for the period 1987 through 2016. These estimates incorporate the appropriate exploration, development, and production timetables for each planning area and field size. They also assume, for comparison purposes, that all resources which are privately worth acquiring are leased in early 1987 (assuming no capital constraints).

Given the complexities and effects of changing economic conditions and geological uncertainty on oil and gas resource estimates, it is useful to examine a number of different types of resource estimates in considering the oil and gas potential of OCS areas. One set of estimates mentioned earlier

is represented by the distribution of conditional economically recoverable oil and gas resources, which represents the potential amounts of oil and gas that could be produced in a particular area assuming that the area contains petroleum and that lease acquisition and exploration costs have been expended. This distribution gives a good indication of the probability of finding and recovering specific amounts of oil and gas under expected economic conditions assuming that exploration has confirmed its presence. The means or average values of the conditional distribution of economically recoverable oil and gas resources also have been estimated for each OCS planning area. The relevant parameters of the conditional distributions of economically recoverable resources are shown in Table 5.

In those areas in which commercial quantities of oil and/or gas have been discovered, the absolute range of conditional resource outcomes is wide; however, Table 5 shows that in virtually all areas the relative size of the range is similar.

For example, in the Central Gulf of Mexico, the marginal probability of finding hydrocarbons is, of course, equal to one. Hence, the risked and conditional distributions of economically recoverable resources are equivalent. For this planning area, the potential size of (unleased) economically recoverable resources ranges from about one-third of the risked mean value at the lower 5 percent end of the distribution, to about 80 percent above the risked mean value at the upper 5 percent of the distribution. (These figures were approximated by adding the available oil and gas figures at each confidence level. This approach yields an exact solution only if the oil and gas are perfectly correlated.)

The relative range of economically recoverable resource estimates around the conditional mean value for frontier areas is similar to that found for the Central Gulf of Mexico, as well as the other proven areas. (The two exceptions are the Beaufort Sea and Norton Basin, which have ranges about two to four times that of the other areas.) For example, in the Navarin Basin, the lower end of the conditional resource distribution is about one-half the conditional mean, while the upper (5 percent) end is about one-half more then the conditional mean. Of course, since the marginal probability of success is 0.27, the risked mean value is one-fourth of the conditional mean and one-half of the lower 5-percent tail of the conditional distribution. These relations suggest the broad range of economically recoverable resources that could result for any given set of economic assumptions.

While it is useful to assess the environmental consequences of leasing in specific areas using conditional resource estimates, it is necessary to consider the "risked" measure of resource amounts in conducting the economic analysis for the 5-year schedule. This is the case because conditional measures generally are not comparable in a meaningful sense among planning areas; the risked measures are comparable since they incorporate the appropriate likelihood of hydrocarbon occurrence.

TABLE 5

Estimates of Undiscovered Economically Recoverable Oil and Gas Resources as of March 1985
Alaska Region

Planning Area	Conditional Oil--BBO 95% Case	Conditional Oil--BBO 5% Case	Conditional Oil--BBO Mean Case	Conditional Gas--TCF 95% Case	Conditional Gas--TCF 5% Case	Conditional Gas--TCF Mean Case	MP_{HC}	Risked Mean Oil (BBO)	Risked Mean Gas (TCF)	Risked BOE (BBOE)
Cook Inlet										
Leased and Unleased	0.06	0.46	0.21	0.08	0.76	0.35	0.03	0.01	0.01	0.01
Unleased	0.03	0.40	0.18	0.04	0.69	0.32	0.03	0.01	0.01	0.01
Leased	0.04	0.12	0.06	0.04	0.15	0.09	0.01	neg.*	neg.*	neg.*
Gulf of Alaska										
Leased and Unleased	0.14	1.00	0.54	1.80	18.46	8.34	0.08	0.04	0.66	0.16
Unleased	0.12	0.86	0.49	1.60	18.26	8.00	0.08	0.04	0.64	0.15
Leased	0.03	0.24	0.10	0.12	0.88	0.40	0.05	0.01	0.02	0.01
Kodiak										
Leased and Unleased	0.04	0.26	0.15	0.58	7.13	2.92	0.05	0.01	0.13	0.03
Unleased	0.04	0.26	0.15	0.58	7.13	2.92	0.05	0.01	0.13	0.03
Leased	0	0	0	0	0	0	0	0	0	0
Shumagin										
Leased and Unleased	0.05	0.09	0.05	0.49	2.65	1.42	0.03	neg.*	0.04	0.01
Unleased	0.05	0.09	0.05	0.49	2.65	1.42	0.03	neg.*	0.04	0.01
Leased	0	0	0	0	0	0	0	0	0	0

* Negligible

TABLE 5

Estimates of Undiscovered Economically Recoverable Oil and Gas Resources as of March 1985
Alaska Region

Planning Area	Conditional Oil--BBO 95% Case	Conditional Oil--BBO 5% Case	Conditional Oil--BBO Mean Case	Conditional Gas--TCF 95% Case	Conditional Gas--TCF 5% Case	Conditional Gas--TCF Mean Case	MP_{HC}	Risked Mean Oil (BBO)	Risked Mean Gas (TCF)	Risked BOE (BBOE)
St. George Basin										
Leased and Unleased	0.82	2.56	1.69	7.33	28.18	15.76	0.22	0.37	3.47	0.99
Unleased	0.37	1.98	1.12	3.42	18.04	9.24	0.22	0.25	2.03	0.61
Leased	0.24	0.91	0.57	2.40	12.04	6.60	0.22	0.13	1.45	0.38
North Aleutian										
Leased and Unleased	0.08	0.76	0.36	0.56	5.25	2.62	0.20	0.08	0.54	0.17
Unleased	0.08	0.76	0.36	0.56	5.25	2.62	0.20	0.08	0.54	0.17
Leased	0	0	0	0	0	0	0	0	0	0
Navarin Basin										
Leased and Unleased	3.05	6.88	4.80	3.65	8.51	5.84	0.27	1.30	1.58	1.58
Unleased	1.81	5.09	3.28	2.34	6.75	4.26	0.27	0.89	1.15	1.09
Leased	0.82	2.30	1.51	0.89	2.26	1.59	0.27	0.41	0.43	0.48
Norton Basin										
Leased and Unleased	0.09	1.64	0.64	0.51	6.31	2.94	0.15	0.09	0.43	0.17
Unleased	0.05	1.02	0.28	0.31	4.26	1.55	0.12	0.03	0.18	0.07
Leased	0.06	1.16	0.47	0.42	3.62	1.81	0.13	0.06	0.24	0.11

TABLE 5

Estimates of Undiscovered Economically Recoverable Oil and Gas Resources as of March 1985
Alaska Region

Planning Area	Conditional Oil--BBO 95% Case	5% Case	Mean Case	Conditional Gas--TCF 95% Case	5% Case	Mean Case	MP_{HC}	Risked Mean Oil (BBO)	Risked Mean Gas (TCF)	Risked BOE (BBOE)
Hope Basin										
Leased and Unleased	0.13	0.40	0.17	0.53	4.12	1.81	0.02	neg.*	0.04	0.01
Unleased	0.13	0.40	0.17	0.53	4.12	1.81	0.02	neg.*	0.04	0.01
Leased	0	0	0	0	0	0	0	0	0	0
Chukchi Sea**										
Leased and Unleased	0.96	4.88	2.68	5.06	27.71	15.10	0.20	0.54	0	0.54
Unleased	0.96	4.88	2.68	5.06	27.71	15.10	0.20	0.54	0	0.54
Leased	0	0	0	0	0	0	0	0	0	0
Beaufort Sea**										
Leased and Unleased	0.23	3.22	1.28	1.01	13.13	5.62	0.70	0.89	0	0.89
Unleased	0.11	1.66	0.65	0.52	6.39	2.98	0.69	0.45	0	0.45
Leased	0.03	2.38	0.60	0.22	8.95	3.18	0.64	0.39	0	0.39
Total Alaska Region										
Leased and Unleased								3.33	6.90	

* Negligible

** In the Chukchi Sea and Beaufort Sea OCS Planning Areas, water depth of 200 feet is considered to be the limit of current arctic production and development technology. Based on current cost/price relationships and foreseeable technological advances, the conditional mean gas resources estimated to exist in the Beaufort Sea and Chukchi Sea Planning Areas are assumed to be noneconomic at this time.

TABLE 5

Estimates of Undiscovered Economically Recoverable Oil and Gas Resources as of March 1985
Atlantic Region

Planning Area	Conditional Oil--BBO 95% Case	5% Case	Mean Case	Conditional Gas--TCF 95% Case	5% Case	Mean Case	MP_{HC}	Risked Mean Oil (BBO)	Risked Mean Gas (TCF)	Risked BOE (BBOE)
North Atlantic										
Leased and Unleased	0.10	0.43	0.26	1.98	9.03	5.06	0.30	0.08	1.52	0.35
Unleased	0.10	0.43	0.26	1.98	9.03	5.06	0.30	0.08	1.52	0.35
Leased	0	0	0	0	0	0	0	0	0	0
Mid-Atlantic										
Leased and Unleased	0.10	0.77	0.36	1.84	11.68	5.98	1.00	0.36	5.98	1.42
Unleased	0.07	0.51	0.24	1.39	8.18	4.21	1.00	0.24	4.21	0.99
Leased	0.01	0.40	0.14	0.20	5.94	2.12	0.79	0.11	1.66	0.41
South Atlantic										
Leased and Unleased	0.37	1.51	0.86	6.78	28.53	16.18	0.25	0.22	4.04	0.94
Unleased	0.34	1.46	0.82	6.30	27.56	15.45	0.25	0.20	3.86	0.89
Leased	0.01	0.09	0.04	0.13	1.41	0.62	0.25	0.01	0.16	0.04
Florida Straits										
Leased and Unleased	0.01	0.12	0.04	0.20	3.79	1.04	0.11	neg.*	0.11	0.02
Unleased	0.01	0.12	0.04	0.20	3.79	1.04	0.11	neg.*	0.11	0.02
Leased	0	0	0	0	0	0	0	0	0	0
Total Atlantic Region										
Leased and Unleased								0.66	11.65	

* Negligible

TABLE 5

Estimates of Undiscovered Economically Recoverable Oil and Gas Resources as of March 1985
Gulf of Mexico Region

Planning Area	Conditional Oil--BBO 95% Case	5% Case	Mean Case	Conditional Gas--TCF 95% Case	5% Case	Mean Case	MP_{HC}	Risked Mean Oil (BBO)	Risked Mean Gas (TCF)	Risked BOE (BBOE)
Eastern Gulf of Mexico										
Leased and Unleased	0.06	1.56	0.41	0.11	9.50	2.19	1.00	0.41	2.19	0.80
Unleased	0.03	1.48	0.36	0.04	8.88	1.63	0.99	0.35	1.62	0.64
Leased	neg.*	0.16	0.06	neg.*	1.49	0.43	0.97	0.06	0.42	0.13
Central Gulf of Mexico										
Leased and Unleased	1.40	6.70	3.75	12.45	64.45	30.69	1.00	3.72	30.69	9.18
Unleased	0.95	4.97	2.66	7.57	36.53	20.64	1.00	2.66	20.64	6.33
Leased	0.27	1.67	0.82	3.58	26.30	7.54	1.00	0.82	7.54	2.16
Western Gulf of Mexico										
Leased and Unleased	0.61	3.64	1.90	10.06	47.92	26.76	1.00	1.90	26.76	6.66
Unleased	0.45	3.31	1.69	7.23	41.05	22.61	1.00	1.69	22.61	5.71
Leased	0.07	0.46	0.22	1.72	8.12	4.34	1.00	0.22	4.34	0.99
Total Gulf of Mexico Region										
Leased and Unleased								6.03	59.64	

* Negligible

TABLE 5

Estimates of Undiscovered Economically Recoverable Oil and Gas Resources as of March 1985
Pacific Region

Planning Area	Conditional Oil--BBO 95% Case	5% Case	Mean Case	Conditional Gas--TCF 95% Case	5% Case	Mean Case	MP_{HC}	Risked Mean Oil (BBO)	Risked Mean Gas (TCF)	Risked BOE (BBOE)
Southern California										
Leased and Unleased	0.84	2.41	1.54	1.37	3.62	2.42	1.00	1.54	2.42	1.97
Unleased	0.61	2.08	1.26	0.97	2.98	1.93	1.00	1.26	1.93	1.60
Leased	0.09	0.56	0.27	0.19	0.83	0.52	1.00	0.27	0.52	0.36
Central California										
Leased and Unleased	0.18	1.01	0.56	0.29	1.38	0.79	0.65	0.36	0.51	0.46
Unleased	0.18	1.01	0.56	0.29	1.38	0.79	0.65	0.36	0.51	0.46
Leased	0	0	0	0	0	0	0	0	0	0
Northern California										
Leased and Unleased	0.15	0.76	0.42	1.17	2.48	1.86	0.60	0.25	1.12	0.45
Unleased	0.15	0.76	0.42	1.17	2.48	1.86	0.60	0.25	1.12	0.45
Leased	0	0	0	0	0	0	0	0	0	0
Oregon/Washington										
Leased and Unleased	0.04	0.54	0.18	2.20	3.62	3.26	0.20	0.04	0.65	0.15
Unleased	0.04	0.54	0.18	2.20	3.62	3.26	0.20	0.04	0.65	0.15
Leased	0	0	0	0	0	0	0	0	0	0
Total Pacific Region										
Leased and Unleased								2.19	4.70	

To obtain the risked levels of economically developable oil and gas resources, a planning area's mean conditional resource levels are multiplied by the chance that geological conditions exist such that the planning area is considered to contain a commercial accumulation of hydrocarbons. This likelihood is defined by the term "marginal probability"; its value for each planning area is shown in Tables 5 and 6. The resulting estimates of risked economically developable oil and gas resources are also provided in Tables 5 and 6. A single measure, called barrels of oil equivalent (BOE), is obtained by converting the risked gas to the Btu equivalent of oil and then simply adding it to the risked oil figure. One barrel of oil contains the heating content of about 5.62 thousand standard cubic feet of gas. The units in Tables 5 and 6 are billions of barrels of oil and trillions of cubic feet of gas. Hence, to obtain (risked) equivalent barrels of oil, we divide the gas amount by 5.62 and add it to the oil amount.

Although these average values are the statistically "best" measures to use in the economic analysis, it is important to reemphasize the inherent uncertainity and variability of the resource estimates. The risked resource size associated with each planning area represents the average results that would emerge if the exploration and development scenario were repeated 5,000 times in an area. Of course, in practice, only one sequence of exploration and development activities will occur in each planning area. Hence, the actual results could differ substantially from the expected results.

The greatest dispersion, or possible range of outcomes around the average results, is associated with frontier areas where the commercial viability of oil and/or gas production has not been established. In these cases, regardless of the average values, an outcome of zero production is not an unrealistic lower-bound estimate. The likelihood of no production is simply one minus the marginal probability of hydrocarbon success, MP_{hc}. For the North and South Atlantic, and all areas of Alaska excluding the Beaufort Sea, the likelihood of zero production is estimated to be at least 0.70.

The March 1985 resource estimates for the various OCS planning areas were adjusted to reflect unleased resources available as of January 1987. This adjustment was made by estimating the quantity of resources that would be leased in each OCS planning area between March 1985 and December 1986 and subtracting that amount from the March 1985 unleased resources. The unleased resources as of January 1987 in each OCS planning area represent the difference between the two numbers. The removal of tracts leased were assumed to have no effect on the marginal probability for the remaining unleased tracts. The unleased resources as of January 1987 are used beginning with Table 6.

In many of the planning areas studied, hundreds of geologic prospects were identified having some likelihood of containing hydrocarbon resources in amounts greater than that size necessary to encourage development, given that the fields have been discovered. However, prior to exploration, many of these developable fields have negative private values adjusted for risk and net of exploration costs.

Thus, in considering the potential for oil and gas discovery, it is appropriate to recognize that discovery results from investments in lease acquisition and exploratory drilling. Under a given set of economic conditions and geologic risk, some prospects are not worth acquiring and drilling even though they would be profitable to develop if such investments had already been made and the deposit found.

Lease acquisition and exploration investments are based upon both the size and the probability of the economic payoffs that can result. The MMS has estimated the risked economically developable oil and gas resources and their net economic value for the prospects that are profitable for private energy companies to invest in lease acquisition and exploration, i.e., they are leasable. These estimates are expressed in "risked" or "expected value" form, which means that the resource amounts and economic values reflect the appropriate probabilities of the different states of (geological) nature that could result. Table 6A shows the estimates of risked resources and expected net economic value from the set of prospects in each OCS area privately worth leasing and exploring.

The economic assumptions for these base case calculations, as described in section VII, include free on board (FOB) port of export oil price of $24.00 in July 1984, a 1 percent real oil and gas annual price increase, an 8 percent discount rate, and a 5 percent inflation rate. A July 1984 price is used as the initial reference price because this analysis began at that time; appropriate adjustments have been made to bring the price to the 1987 level. Applying these assumptions and employing the techniques described in section VII, the net economic values as of January 1987 have been calculated and are contained in Table 6A. The four lowest ranked planning areas in Table 6 are deleted from Table 6A and subsequent tables in this appendix because their current economically recoverable resource magnitudes are estimated to be negligible.

The aggregate magnitude and value of leasable resources do not, however, provide a complete picture of the resource and economic potential of an area. This is so because a substantial total net economic value may result from a moderate amount of high-valued resources or a very substantial amount of lower valued resources. Table 7 shows how the resource potential is distributed by net economic value in each area.

Table 8 evaluates the effects of alternative price assumptions ($19, $24, and $29 in 1984 dollars) on the amount of developable resources that is on leasable prospects for each of the 20 planning areas. Because of continuing decreases in the price of oil over the past year, accompanied by an increasingly pessimistic outlook on price expectations, a $19 per barrel scenario is examined indicating that two additional areas, Beaufort Sea and St. George Basin, have negligible leasable prospects(e.g., prospects having economically recoverable resources which have a positive private value) and NEV's. Table 8 shows that some areas, such as the Chukchi Sea, Gulf of Alaska, St. George Basin, North Aleutian Basin, Norton Basin, and the North Atlantic have much better leasing possibilities at the $29 (high price) scenario.

An important consideration in deciding when to offer the potential resources in a given planning area for lease, or how to order the offering of all planning areas, is the cost of delaying the sale (and hence, presumably, exploration and development) of leasable prospects. In cases where the net economic value per barrel can be increased in present worth from future rather than current offerings, such planning areas should be timed for sale later (if at all) in the schedule.

Measures of the cost of delay for currently (January 1987) leasable prospects in each planning area for the base case are presented in Table 9. These measures were developed under both 1- and 2-percent real oil price increase scenarios over a one-year delay interval. A delay in leasing is assumed to result in an equivalent delay in the start of exploration. For a given real oil price increase, the declines in net economic value per barrel (i.e., the "delay costs") are computed by finding the per barrel change in net economic value for fields that are leasable as of January 1987. The largest delay costs, equal to about 6 percent of net economic value per year of delay, are incurred for the highest valued planning areas including the Gulf of Mexico and Pacific Regions. The relative size of delay costs would be higher if no price increase were expected.

Observe in Table 9 that most entries are negatively valued. This means essentially that within each of the relevant planning areas, a delay in leasing, which results in postponement of the start of exploration activities, will cause a reduction in the net economic value per barrel of oil that would be produced if hydrocarbons were discovered in an average leasable field. For a few high-cost, low-valued leasable fields in selected areas, the change in net economic value from delay will be positive. A preliminary analysis of the field size distributions suggests, however, that only a small percentage of the leasable resources in all planning areas will have this attribute.

The net economic value of a barrel of oil and gas in the 2-percent price growth case is higher than in the 1-percent case. Moreover, the set of leasable prospects may differ somewhat for each price scenario. Thus, for a given planning area, the delay costs per barrel as presented in Table 9 are not directly comparable between price scenarios. Of course, for a given price change assumption, the dollar measures of delay costs do suggest the proper ordering of leasing and investment among areas.

E. Implications of Resource and Net Economic Value Estimates for Schedule Formulation

The guidelines for leasing program formulation developed in section V and the measures of oil and gas resources and net economic value in OCS areas provided in this section can be used to develop a leasing schedule based on economic factors alone. While such a schedule does not reflect consideration of the many noneconomic factors that must be weighed, it provides a base from which adjustments for those factors can be made.

The primary guideline for formulating an economically efficient leasing program is to offer the areas with the highest valued prospects earliest and the areas with the greatest total economic value most frequently. This guideline allows investments to be made in a sequence that would be a reasonable approximation of the most efficient sequence, namely from lowest cost to highest cost deposits.

As Table 7 shows, the Central and Western Gulf of Mexico areas have by far the greatest resource potential in the highest value categories, approximately 4.5 billion barrels each. These two areas also have the greatest total net economic value and the greatest total leasable resources. In addition, both areas have substantial resource potential at lower net economic values, which would increase in relative value over time as other areas were leased. The sensitivity of the leasable resources in the Central Gulf of Mexico planning area to a $5 per barrel increase/decrease in the starting oil price is contained in Table 8.

Based on these indicators of the resource and economic potential of the Central and Western Gulf of Mexico, it would be reasonable to schedule sales in these areas for each year in the 5-year program. This would continue the frequency of leasing under the current program. The amount of leasing and the value of leases sold in such annual sales would be expected to decrease unless prices increased suddenly or significant new prospects were identified; however, annual leasing in these two areas is warranted until the unleased inventory is sufficiently depleted to fall more nearly in line with that of other OCS areas.

Outside the Central and Western Gulf of Mexico, the Eastern Gulf of Mexico and the three California planning areas have by far the greatest amount of high valued leasable resources (see Table 7.) The Southern California area has the largest portion of these high-valued resources in the top net economic value categories and as many leasable resources as the Eastern Gulf of Mexico and the Central and Northern California planning areas combined. The estimated cost of delaying investments in the leasable resources (at the base case assumption of a 1 percent price growth) is approximately the same for the Northern and Central California planning areas, somewhat higher for Southern California, and somewhat less for the Eastern Gulf of Mexico. Thus, while the relatively high economic value of the resource potential in these areas makes it reasonable to schedule more than one lease sale in each area during the 5-year program, priority for earlier sales should be given to the Southern California area.

The South Atlantic and Navarin Basin planning areas also rank high in estimated leasable resources with total net economic values of approximately $2.1 and $1.4 billion (see Table 6). However, the South Atlantic also has a higher geologic risk than the Gulf of Mexico or areas offshore California and the Navarin Basin has much higher costs. The South Atlantic was offered for sale three times since 1978, and Sale 90 which was scheduled for July 1985 is now "on hold." The estimates show that this area may warrant sales in the 1987-1991 leasing program, perhaps more than one sale if exploration yields positive results. Consideration of industry interest and noneconomic factors must also be weighed in addition to the net economic value basis for scheduling.

The next group of prospective areas in Table 7 are the Beaufort Sea and the Mid-Atlantic. The Beaufort Sea has about one-third more leasable resources then the Mid-Atlantic, but a lower net economic value per barrel in the base case. However, the Beaufort Sea shows a greater gain in leasable resources from higher prices. Since the estimated net economic value for each of these areas is in the $0.3 to $0.5 billion range, it is reasonable to offer both areas at least once in the 1987-1991 program.

The last three areas that currently have resources which appear to make worthwhile acquisitions are the St. George Basin, North Atlantic, and Washington-Oregon. The estimated net economic value of leasable resources is in the neighborhood of $0.15 to $0.35 billion for these areas. They have relatively little resource potential in high-value prospects (see Tables 7), however, the North Atlantic could gain substantially from a higher oil/gas price level. Delay costs are moderate, except for Washington-Oregon, which reflects the relatively high per barrel value of the limited resources in that area. These findings make it worth offering the areas at least once during the 1987-1991 period to allow firms the opportunity to invest in gathering more seismic data and exploring the potentially profitable unleased prospects.

Of the remaining areas with resource potential, the MMS estimates show one with some current leasable resource potential (Florida Straits) and eight with negligible resource potential; namely, the Chukchi Sea, North Aleutian Basin, Gulf of Alaska, Norton Basin, Kodiak, Hope Basin, Shumagin, and Cook Inlet. None of the latter four areas show any leasable resource gain from the $5 per barrel higher oil price level. The other areas, with the exception of the Chukchi Sea, are marginal. The Chuckchi Sea shows a large gain in leasable resources with a $5 per barrel increase in oil prices, ranking it about equal with Central and Northern California, however the Chukchi Sea's net economic value is still much lower. To be able to offer these remaining areas if new information should make them more valuable, they might be scheduled for standard or tentative sales.

Again, please note that these analyses are based on a (price) sensitivity analysis around the risked mean recoverable resource estimated for an area. Therefore, a considerable degree of uncertainty exists in all of the estimates. Likewise, although the various tables appear to be accurate to five places, that appearance is misleading and exists only to facilitate calculations. The tables are used primarily for ordinal rather than cardinal ranking of planning areas.

TABLE 6

UNDISCOVERED ECONOMICALLY RECOVERABLE RESOURCES UNLEASED AS OF 1/87

Rank 1/	Planning 2/ Area	Cond'l Mean Oil (BBO)	Cond'l Mean Gas (TCFG)	MP_{hc}	Risked Mean Oil (BBO)	Risked Mean Gas (TCFG)	Risked BOE (BBOE)
1	Central Gulf of Mexico	7.11	17.28	1.00	7.11	17.28	5.18
2	Western Gulf of Mexico	1.32	18.62	1.00	1.32	18.62	4.63
3	Southern California	1.26	1.93	1.00	1.26	1.93	1.60
4	Navarin Basin	3.28	4.26	0.27	0.89	1.15	1.09
5	South Atlantic	0.82	15.45	0.25	0.20	3.86	0.89
6	Mid-Atlantic	0.20	3.35	1.00	0.20	3.35	0.80
7	Eastern Gulf of Mexico	0.30	1.58	1.00	0.30	1.58	0.58
8	Chukchi Sea	2.68	-0-	0.20	0.54	-0-	0.54
9	Beaufort Sea	0.65	-0-	0.70	0.46	-0-	0.46
10	Central California	0.56	0.79	0.65	0.36	0.51	0.46
11	Northern California	0.42	1.86	0.60	0.25	1.12	0.45
12	St. George Basin	0.64	5.99	0.22	0.14	1.32	0.38
13	North Atlantic	0.26	5.06	0.30	0.08	1.52	0.35
14	Washington-Oregon	0.18	3.26	0.20	0.04	0.65	0.15
15	Gulf of Alaska	0.49	8.00	0.08	0.04	0.64	0.15
16	North Aleutian Basin	0.19	1.36	0.20	0.04	0.27	0.09
17	Norton Basin	0.13	0.59	0.15	0.02	0.09	0.04
18	Kodiak	0.15	2.92	0.05	0.01	0.13	0.03
19	Florida Straits	0.04	1.04	0.11	negligible	0.11	0.02
20	Hope Basin	0.17	1.81	0.02	negligible	0.04	0.01
21	Shumagin	0.05	1.42	0.03	negligible	0.04	0.01
22	Cook Inlet	0.18	0.32	0.03	0.01	0.01	0.01

1/ Ranking based on risked BOE

2/ In the Beaufort and Chukchi Sea planning areas, 200 feet water depth is considered to be the limit of current technology. Based on current cost/price relationships and forseeable technological advances, it is assumed that the conditional mean gas resources estimated to exist in the Alaskan OCS Beaufort Sea and Chukchi Sea Planning Areas are uneconomic.

TABLE 6A

NET ECONOMIC VALUE ESTIMATES FOR LEASABLE RESOURCES AS OF 1/87

Planning Area	Risked Economically Recoverable Oil and Gas Resources (MM-BOE)	Fraction of Recoverable Resource That is Leasable	Risked Economically Leasable Resources 1/ (MM-BOE)	Net Economic Value per BOE	Total Net Economic Value ($MM)
Central Gulf of Mexico	5,180	0.900	4,662	5.84	27,226
Western Gulf of Mexico	4,630	1.000	4,630	5.13	23,752
Southern California	1,600	0.776	1,241	5.37	6,664
Navarin Basin	1,080	0.662	722	1.94	1,401
South Atlantic	890	0.717	638	3.28	2,093
Mid-Atlantic	800	0.230	184	2.63	484
Eastern Gulf of Mexico	580	0.718	416	3.81	1,585
Chukchi Sea	540	0.000	0	0 (1.03)*	0
Beaufort Sea	460	0.540	248	1.36	337
Central California	460	0.880	405	4.60	1,863
Northern California	450	0.920	414	4.47	1,851
St. George Basin	380	0.421	160	1.42	227
North Atlantic	350	0.100	35	4.21	147
Washington-Oregon	150	0.373	56	6.19	347
Gulf of Alaska	150	0.000	0	0 (0.58)	0
North Aleutian Basin	90	0.000	0	0 (0.25)	0
Norton Basin	40	0.000	0	0 (1.51)	0
Kodiak	30	0.000	0	0 (1.25)	0
Florida Straits	20	0.300	6	4.03	24
Hope Basin	10	0.000	0	0 (0.68)	0
Shumagin	10	0.000	0	0 (1.34)	0
Cook Inlet	10	0.000	0	0 (1.44)	0

Assumptions: Base Case

Starting Oil Price: $24
Annual Oil Price Change: 1 percent
Discount Rate: 8 percent
Resources Expressed in Millions of Equivalent Barrels (MMBOE)

* The net economic values in parends represent the estimated value for those cases in which the after-tax net present value in the planning area is equal to zero.

1/ "Risked Economically Leasable Resources" are calculated by multiplying "Risked Economically Recoverable Oil and Gas Resources", by the "Fraction of Recoverable Resource That is Leasable" at a starting oil price of $24 per barrel.

TABLE 7

CONDENSED DISTRIBUTION OF RISKED DEVELOPABLE RESOURCES AS OF 1/87
(MILLIONS OF EQUIVALENT BARRELS)
AT ($19/BOE), $24/BOE, [$29/BOE]

Planning Area	Recoverable But Not Leasable	Net Economic Value per BOE for Leasable Resources: Below $3.00	$3.00 to $6.00	$6.00 to $10.00
Central Gulf of Mexico	(577) 518 [518]	(303) 59 [0]	(4,300) 2,902 [1237]	(0) 1,701 [4,539]
Western Gulf of Mexico	(139) 0 [0]	(1,847) 139 [0]	(2,644) 3,792 [543]	(0) 690 [4,087]
Southern California	(554) 359 [336]	(429) 195 [0]	(617) 504 [478]	(0) 547 [790]
Navarin Basin	(912) 368 [305]	(178) 722 [269]	(0) 0 [516]	(0) 0 [0]
South Atlantic	(498) 257 [160]	(392) 214 [268]	(0) 424 [462]	(0) 0 [0]
Mid-Atlantic	(712) 416 [616]	(88) 96 [96]	(0) 88 [88]	(0) 0 [0]
Eastern Gulf of Mexico	(749) 163 [109]	(300) 86 [54]	(31) 318 [206]	(0) 13 [211]
Chukchi Sea	(540) 540 [140]	(0) 0 [400]	(0) 0 [0]	(0) 0 [0]
Beaufort Sea	(460) 212 [152]	(0) 248 [308]	(0) 0 [0]	(0) 0 [0]
Central California	(140) 55 [55]	(278) 34 [0]	(92) 279 [276]	(0) 92 [129]
Northern California	(169) 34 [34]	(130) 133 [0]	(158) 130 [228]	(0) 151 [186]
St. George Basin	(380) 220 [220]	(0) 160 [160]	(0) 0 [0]	(0) 0 [0]
North Atlantic	(315) 315 [276]	(22) 0 [28]	(13) 35 [22]	(0) 0 [13]
Washington-Oregon	(104) 94 [86]	(0) 10 [0]	(46) 13 [101]	(0) 33 [46]
Gulf of Alaska	(150) 150 [122]	(0) 0 [28]	(0) 0 [0]	(0) 0 [0]
North Aleutian Basin	(90) 90 [74]	(0) 0 [16]	(0) 0 [0]	(0) 0 [0]
Norton Basin	(40) 40 [28]	(0) 0 [12]	(0) 0 [0]	(0) 0 [0]
Kodiak	(30) 30 [30]	(0) 0 [0]	(0) 0 [0]	(0) 0 [0]
Florida Straits	(14) 14 [14]	(6) 0 [0]	(0) 6 [6]	(0) 0 [0]
Hope Basin	(10) 10 [10]	(0) 0 [0]	(0) 0 [0]	(0) 0 [0]
Shumagin	(10) 10 [10]	(0) 0 [0]	(0) 0 [0]	(0) 0 [0]
Cook Inlet	(10) 10 [10]	(0) 0 [0]	(0) 0 [0]	(0) 0 [0]

Assumptions: Base Case

Starting Oil Price: $24
Annual Oil Price Change: 1 percent
Discount Rate: 8 percent

TABLE 8

SENSITIVITY OF LEASABLE RESOURCE AMOUNTS AND
NET ECONOMIC VALUE (NEV) TO THE STARTING OIL PRICE

Planning Area	Starting Price: $19 Leasable Resources (MM-BOE)	NEV ($/BOE)	Total NEV ($MM)	Starting Price: $24 Leasable Resources (MM-BOE)	NEV ($/BOE)	Total NEV ($MM)	Starting Price: $29 Leasable Resources (MM-BOE)	NEV ($/BOE)	Total NEV ($MM)
Central Gulf of Mexico	4,603	3.88	17,860	4,662	5.94	27,726	4,662	7.56	35,245
Western Gulf of Mexico	4,491	3.23	14,506	4,630	5.13	23,752	4,630	6.76	31,290
Southern California	1,046	3.80	3,975	1,241	5.37	6,664	1,264	7.19	9,088
Navarin Basin	178	0.68	121	722	1.94	1,401	785	3.30	2,591
South Atlantic	392	2.14	839	638	3.28	2,093	730	4.14	3,022
Mid-Atlantic	88	2.25	198	184	2.63	484	184	3.93	723
Eastern Gulf of Mexico	331	2.04	675	416	3.81	1,585	470	5.05	2,379
Chukchi Sea	0	0	0	0	0	0	400	1.49	596
Beaufort Sea	0	0	0	248	1.36	337	308	2.20	678
Central California	320	2.39	765	405	4.60	1,863	405	6.54	2,649
Northern California	281	3.24	910	414	4.47	1,851	414	5.95	2,463
St. George Basin	0	0	0	160	1.47	227	160	2.90	464
North Atlantic	35	2.43	85	35	4.21	147	74	3.49	258
Washington-Oregon	46	4.50	207	56	6.19	347	56	8.11	454
Gulf of Alaska	0	0	0	0	0	0	28	1.19	33
North Aleutian Basin	0	0	0	0	0	0	16	1.28	20
Norton Basin	0	0	0	0	0	0	12	1.66	20
Kodiak	0	0	0	0	0	0	0	0	0
Florida Straits	6	2.27	14	6	4.03	24	6	5.49	33
Hope Basin	0	0	0	0	0	0	0	0	0
Shumagin	0	0	0	0	0	0	0	0	0
Cook Inlet	0	0	0	0	0	0	0	0	0

Assumptions: Base case with price sensitivity

Starting Oil Price: $24
Annual Oil Price Change: 1 percent
Discount Rate: 8 percent
Resources Expressed in Millions of Equivalent Barrels (MMBOE)

TABLE 9

SIMPLE AVERAGE ANNUAL DOLLAR CHANGE IN NET ECONOMIC VALUE PER BARREL FOR LEASABLE RESOURCES FROM A ONE-YEAR DELAY IN LEASING

	Price = $19/BOE			Price = $24/BOE			Price = $29/BOE		
Discount Rate =	8%	8%	6%	8%	8%	6%	8%	8%	6%
Price Growth =	1%	2%	2%	1%	2%	2%	1%	2%	2%
Planning Area									
Central Gulf of Mexico	-.22	-.22	-.19	-.35	-.35	-.31	-.46	-.46	-.41
Western Gulf of Mexico	-.17	-.17	-.14	-.29	-.29	-.26	-.40	-.40	-.36
Southern California	-.21	-.20	-.16	-.30	-.29	-.24	-.39	-.37	-.32
South Atlantic	-.10	-.12	-.12	-.16	-.18	-.18	-.21	-.24	-.23
Mid-Atlantic	-.10	-.11	-.10	-.11	-.12	-.12	-.19	-.25	-.24
Eastern Gulf of Mexico	-.08	-.08	-.05	-.19	-.19	-.16	-.29	-.29	-.25
Chukchi Sea	*	*	*	(-.03)*	(-.06)*	(-.05)*	-.09	-.12	-.12
Navarin Basin	+.01	0	+.01	-.07	-.08	-.07	-.11	-.13	-.11
Central California	-.09	-.08	-.06	-.26	-.25	-.20	-.35	-.35	-.29
Northern California	-.17	-.15	-.12	-.25	-.24	-.19	-.32	-.31	-.25
St. George Basin	*	*	*	-.03	-.05	-.03	-.12	-.14	-.12
North Atlantic	-.11	-.12	-.11	-.23	-.24	-.22	-.16	-.18	-.17
Beaufort Sea	*	*	*	-.05	-.08	-.08	-.10	-.14	-.14
Washington-Oregon	-.25	-.24	-.19	-.36	-.34	-.27	-.40	-.38	-.30
Gulf of Alaska	*	*	*	(+.02)*	(-.01)*	(0)*	-.02	-.04	-.03
North Aleutian Basin	*	*	*	(+.04)*	(+.05)*	(+.04)*	-.02	-.05	-.04
Norton Basin	*	*	*	(-.04)*	(-.06)*	(-.05)*	-.04	-.05	-.04
Kodiak	*	*	*	(-.03)*	(-.06)*	(-.05)*	*	*	*
Florida Straits	-.10	-.11	-.10	-.22	-.22	-.21	-.31	-.32	-.29
Hope Basin	*	*	*	(+.02)*	(0)*	(+.02)*	*	*	*
Shumagin	*	*	*	(-.03)*	(-.06)*	(-.05)*	*	*	*
Cook Inlet	*	*	*	(-.05)*	(-.07)*	(-.06)*	*	*	*

Assumptions: Base case with price sensitivity

Starting Oil Price: $24
Annual Oil Price Change: 1 percent
Discount Rate: 8 percent
Resources Expressed in Millions of Equivalent Barrels (MMBOE)

* Area has a negative net economic value per barrel for the selected price/discount rate scenario if both oil and gas are considered. For the base case starting price, numbers in parentheses indicate the change in net economic value that results if the planning area's net economic value that corresponds to the after-tax net present value of zero is used.

Note: Any positive values indicate areas which gain in net economic value, if leasing were delayed.

VII. Estimating Procedures Used for Analysis of OCS Planning Areas

A. Introduction

Formulation of a 5-year OCS leasing schedule requires a determination of where, when, and how the oil and gas resources that are potentially located in the planning areas would be made available for sale to private industry. In addressing these salient issues, it is important to develop estimates relating to the geologic and economic characteristics of the designated OCS planning areas. This section gives a technical description of the methods and assumptions used to generate the estimates presented in section VI and Appendix E.

B. Geologic Analysis

Estimates of oil and gas resources and economic values for the designated OCS planning areas allow a ranking of planning areas to be made. This is an important first step in designing a lease schedule. The absolute size of the economic values within a planning area provide for a comparison with the associated environmental risks and costs to determine the overall net social value of each planning area.

The basic unit of oil and gas resources that was measured is called economically recoverable oil and gas resources. This estimate represents the magnitude of oil and gas equivalent barrels that are profitable for a lessee to produce, given that the resource has already been discovered. In this context, economically recoverable resources are "conditional," i.e., they are measured free of the risk of discovery and production. For a given distribution of conditional economically recoverable oil and gas resources, the average value of the distribution is the mean conditional economically recoverable oil and gas resource level.

When the possibility for success/failure in discovery or production of the resources is taken into consideration, economically recoverable resources are expressed in terms of "risked" or "expected" resources. This means that production will occur only if three specific states of nature exist. First, the planning area must be hydrocarbon-prone. Second, the geologic prospect upon which the resources could occur must contain hydrocarbons. Finally, the amount of hydrocarbons found must be economical to produce. The resulting joint probability is referred to as the "probability of economic success."

Assuming that the probability of success and the conditional resource size are independent, the product of the mean conditional economically recoverable resource level and the economic success probability results in an estimate of producible resources on the geologic prospect and is denoted by the term "risked conditional economically recoverable resources," or simply "risked recoverable resources."

Calculation of the conditional resource sizes and economic successes for exogenously selected geologic prospects in the OCS planning area was done using a computer simulation model called PRFSTO, an acronym for "probabilistic

resource estimates--OCS." The data available for this 5-year assessment were taken from stratigraphic tests, well logs, and geophysical analyses. These These data were generally adequate to identify potential prospects and to determine their approximate size. In some instances, however, hypothetical prospects based on extrapolations of known trends and appropriate geological analogs were included. This was necessary because some areas lacked sufficient data to adequately identify individual prospects. Therefore, with the hypothetical prospects it was possible to analyze the resource potential of an area on a prospect-by-prospect basis. In some areas, sufficient stratigraphic data may exist to identify different resource potential on a horizon-by-horizon basis, as well as on a prospect-by-prospect basis. Therefore, the PRESTO methodology was designed to accommodate an analysis of hydrocarbon resource potential for an area on both a horizon-by-horizon and a prospect-by-prospect basis.

A volumetric method was employed for the analysis of the resource potential of individual prospective zones. Seven variables were considered in determining potential hydrocarbon volumes: (1) productive area (acres), (2) pay thickness (feet), (3) proportion of pay in oil reservoirs, (4) oil recovery factor for oil reservoirs (barrels per acre-foot), (5) gas-oil ratio (cubic feet of associated gas per barrel), (6) gas recovery factor for gas reservoirs (thousands of cubic feet of nonassociated gas per acre-foot), and (7) condensate yield ratio for liquids produced from gas reservoirs (barrels per million cubic feet of nonassociated gas). Either single point values for each of these variables or parameters describing a probability distribution were used.

In addition to the reservoir parameters, several other inputs were used. For each zone in each prospect, a zone geologic risk factor was estimated. This risk factor represents the overall probability that the zone in the prospect under consideration will be dry. For each prospect, two additional input values were required--a "minimum economic field size" for the prospect and a prospect geologic risk factor. The minimum economic field sizes were developed using a combination of sophisticated cash flow models, general rules, and empirical data on producing tracts. These values represent the minimum quantity of oil and gas that must be present in a prospect to be considered economically producible given current and expected future cost/price relationships and technological trends. The minimum economic field size allows for variations in costs associated with the exploration and development of prospects in differing cost regimes, such as deep water vs. shallow water.

The prospect risk factor represents the probability that the prospect as modeled would not contain hydrocarbons, without including additional considerations unique to individual zones. In addition to the zone and prospect geologic risk factors, a probability which applies to the area under consideration as a whole was required. This area risk factor represents the likelihood that no prospect as modeled would contain hydrocarbons.

The prospect risk factor controlled the degree of statistical dependence for discovery among the individual zones. A high value indicates a high degree of dependence, which implies that a discovery in one zone greatly increases

value implies that the risks associated with individual zones are unrelated, i.e., a discovery in one zone has little effect on the chances for discovery in other zones. The area risk factor works in the same manner; however, it controls the dependency for discoveries among the individual prospects rather than individual zones.

Monte Carlo or range-of-values simulation techniques were used to develop a conditional probability distribution for each area as a whole. This technique explicitly recognizes the probabilistic nature of the variables affecting the resource assessment and calculates a large number of possible outcomes, based upon random samples from the probability distributions of the various inputs. The Monte Carlo technique generated a range of resource estimates for a planning area with the probability of each value occurring being a direct consequence of the uncertainty in the geological and engineering data (e.g., areal extent and thickness of the hydrocarbon pay zone, recovery factors, and which prospects and/or combination of prospects will contain hydrocarbons). Specific oil and gas amounts corresponding to the mean value, 5th percentile, and 95th percentile values of the distribution for barrel of oil equivalents of total resources were reported. Also reported was the probability that no economically recoverable resources exist in the area under consideration.

It is worth noting that, under economic conditions expected to exist, prospects that are not profitable to develop are not considered by PRESTO. In this sense, the resource estimates are conservative, and the sensitivity of resource potential to large increases in the price of oil tends to be understated.

The most important outputs produced by PRESTO for each planning area are: (1) identification of the remaining prospects that were partially or fully unleased as of March 1985, (2) their probability of economic success, (3) their mean conditional recoverable resource sizes, and (4) their minimum economic field sizes. In all, over 2,400 prospects were evaluated. (The effect of lease sales during the 1985 to 1986 period on the unleased resource inventory was calculated exogenously from PRESTO.)

The MMS divided the OCS into 26 planning areas. PRESTO was then run for each area. Four areas (Aleutian Basin, Bower Basin, St. Matthew-Hall, and Aleutian Arc) were dropped from further consideration in this appendix after their recoverable hydrocarbon potential was computed to be insignificant.

C. Economic Analysis

After the PRESTO outputs were produced, a procedure was developed to compute appropriate measures of economic value for the prospects within each planning area. The inputs needed to conduct the economic analysis, using the TSL80 computer leasing model, did not correspond perfectly with the previously designated outputs of PRESTO (see "Guide for Using the Leasing Simulation Computer Program TSL80 (Version OCT16)", Minerals Management Service, U.S. Department of the Interior, October 23, 1984).

For example, the probability input requirement for TSLBO is not "economic success" which the PRESTO runs developed; it is "geologic success" (i.e., the joint probability of the planning area being hydrocarbon-prone and the prospect containing hydrocarbons). This is the case because TSLBO endogenously computes the likelihood of producing the resource after a discovery of a given amount has occurred. Fortunately, one of the intermediate outputs of PRESTO is called "non-producing trials." Knowledge of this and the total number of simulation trials permitted the calculation of the geologic success used in the TSLBO calculations.

A more complicated problem arose regarding the TSLBO input parameters for the conditional resource distribution. TSLBO requires that the mean, standard deviation, and shape of the input distribution be expressed in terms of geologic resources, not economic resources, as is the case with PRESTO outputs. However, the mean conditional economically recoverable resource size for a geologic prospect as described by PRESTO can be expressed as the expectation of a geologic distribution of resources for that prospect truncated at the minimum economic field size. In order to find the mean conditional size of the geologic distribution of resources for a given prospect, it was necessary to derive the expectation of the untruncated distribution.

To accomplish this, the following methodology was developed. For each prospect, the mean of the conditional geologic resource distribution can be expressed as the weighted average of the mean conditional size of economically recoverable resources (a PRESTO output) and the mean of truncated left tail of the original geologic distribution. By approximating the latter distribution as triangular, with mode = maximum value = minimum economic field size, it can be demonstrated that the mean of this second distribution is simply two-thirds of the minimum economic field size. The weights used were proportional to the areas of each distribution, i.e., the ratio of "successful" trials to total trials for developable resources (or the economic success given that the planning area is hydrocarbon prone) and the ratio of "unsuccessful" trials to total trials for the left tail of the original distribution.

The shape of the geologic distributions of field sizes was assumed to be lognormal. This derives from the multiplicative processes that account for hydrocarbons. Empirical evidence of discovered fields supports this assumption.

The final parameter derived was the variance of the field size distributions. In each of the four OCS Regions, the standard deviation relative to the mean of the conditional geologic resource size, known as the coefficient of variation, was analyzed for selected past sales using data produced by the official tract evaluation model called MONTCAR. Then, assuming the geologic success probability, TSLBO was run with different values of the coefficient of variation to determine the ones which best produced the associated economic success rates. This procedure permitted the selection of a representative parameter for the coefficient of variation for geologic prospects in each Region (see Table 10).

Within a planning area, measures of economic value per barrel differ by field size because of the fixed nature of exploration costs and economies of scale

TABLE 10

REGIONAL INPUTS USED IN ECONOMIC EVALUATIONS

Region	Input: Coefficient of Variation for MCGR*	Input: Water Depth Demarcation (meters)
Alaska	1.00	**
Atlantic	1.00	200
Gulf of Mexico	0.36	400
Pacific	0.36	200

* MCGR = mean conditional geologic resources

** Area dependent and ranges from 200 meters in ice-free locations--Gulf of Alaska, etc., to 20 meters in sites such as the Beaufort and Chukchi Seas.

in platform construction. For fields of a given size, the per barrel values also vary depending upon water depth, the fraction of the field which has already been leased, and other factors such as distance from existing pipelines.

The water-depth parameter was divided into two categories for each of the four Regions (see Table 10). The demarcation line was selected to coincide with that isobath currently used to distinguish between tracts which receive the one-sixth (shallow water) and those receiving one-eighth (deep water) fixed royalty rates. The selection of the relevant isobaths for royalty terms is based on identification of the location of the most pronounced change in development costs and technology in each Region.

The original size of fields that are now partially leased was identified from the "leased" and "unleased" sections of the PRESTO runs. Distance from pipelines was incorporated as part of the transportation cost scenario for a given field size/water-depth/planning area configuration.

At this stage, a decision was made on the specific field sizes to be analyzed using TSL80. A statistical analysis was conducted to determine whether the geologic success (GS) was related to the mean conditional geological resource (MCGR) size. These tests showed conclusively that, with the exception of a few special cases, there was little or no significant relationship between these variables within a planning area. As a result, only one GS rate had to be specified within a category of tracts for a planning area. For each planning area, a distribution of MCGR by water depth was computed for unleased prospects. These distributions were then segmented into nine categories of field sizes. Each category was run through TSL80, using the geological parameters discussed earlier as well as the economic assumptions described in the following subsection.

The relevant TSL80 outputs for each field size, water depth, and planning area consisted of estimates of economic risk, conditional and risked economically developable resources, the private after-tax value and the net economic value. These outputs formed the basis for the summary tables presented in section VI.

D. Economic Assumptions

The primary economic parameters used in the TSL80 computer model were capital costs (platforms and wells) and production profiles, transportation modes and costs, prices per barrel of oil equivalent, public and private opportunity costs of capital, and inflation rates. The input assumptions used for these parameters are discussed in this section. All dollar amounts are expressed in dollars as of 1/87, except for the discussion on oil prices.

1. Capital Costs

The capital costs were determined parametrically and differed not only from planning area to planning area, but also differed within planning areas by water depth (shallow versus deep) and field size. Costs for wells, platforms, etc., were the lowest in shallow water areas of the Gulf of Mexico where extensive infrastructure already exists to support oil and gas operations. The highest capital cost levels were prevalent in deepwater frontier areas and the arctic waters off Alaska. This means that an appropriately larger minimum economic field size (compared to that in the Gulf of Mexico) is necessary for production, given that hydrocarbons have been found on the prospect. As a result, capital costs ranged from tens of million of dollars for a small field in shallow water in the Gulf of Mexico to well over a billion dollars for a large field in deepwater frontier or arctic areas.

In addition, well and production costs used for the base price ($24/BOE) and low price ($19/BOE) scenario assume no nominal increase from 1984 levels because of low demand for drilling services. However, with the high oil price case ($29/BOE), well and production costs are assumed to increase at the inflation rate from 1984 to 1987 due to higher demand for factors of production at the higher price.

The representative minimum recoverable economic field sizes listed below show the diverse intraplanning and interplanning area capital costs.

Atlantic--Minimum economic field sizes ranged from 1 to 2 million (conditional) barrels in shallow water to 280 million barrels in deep water, with a cluster of deepwater fields in the 100- to 150-million barrel range. Costs varied from the tens of millions of dollars for small fields in shallow water to over $1 billion for large fields in deep water.

Gulf of Mexico--Minimum economic field sizes ranged from 1 to 2 million barrels in shallow water to 190 million barrels in deep water, with a cluster of deepwater fields in the 80- to 120-million barrel range. Costs varied from tens of millions of dollars for small fields in shallow water to over 1 billion dollars for large fields in deep water.

Pacific--Minimum economic field sizes ranged from 9 to 14 million barrels in shallow water to 123 million barrels in deep water, with a cluster of deepwater fields in the 40- to 80-million barrel range. Costs varied from the tens of millions of dollars for small fields in shallow water to the high hundreds of millions of dollars for large fields in deep water.

Alaskan--Minimum economic field sizes ranged from 67 to 100 million barrels in shallow water in non-arctic areas to over 200 million barrels in arctic areas. The largest minimum economic field sizes were 225 million barrels in non-arctic areas to over 440 million barrels in arctic areas. Costs varied from the hundreds of millions of dollars for small fields in non-arctic areas to billions of dollars for large fields in arctic areas.

Production profiles also differed among planning areas with currently producing areas requiring, in general, less time for exploration, delineation, and development than frontier areas. Discount factors for regional production profiles and revenue streams are presented in Table 11 and the timing of representative production profiles is presented in Table 11A.

2. Transportation Costs

Transportation costs differed from planning area to planning area due primarily to the existence or lack of extensive pipeline systems. This difference is significant because transportation costs are subtracted from the expected market price in estimating the net economic value of oil and gas in each OCS planning area. Currently, the Central and Western Gulf of Mexico and, to a lesser extent, the California OCS have extensive pipeline systems, including a network of oil and gas gathering systems and trunk lines. Although pipelines are generally used to bring resources ashore from the California OCS, tankers may be used to transport oil to either west or gulf coast refineries. In areas currently not under production (e.g., the Atlantic and Alaska), the transportation mode cannot be determined until the amount of recoverable resources is known. Pipeline transport is the preferred alternative; however, tankering of oil may be used for environmental considerations or because resource levels do not economically justify laying pipelines.

For our analysis, the following transportation cost assumptions were made:

Atlantic--Pipelines will be used to transport oil and gas to shore for processing at facilities along the Atlantic coast. If the discovered reserves are too low to justify pipelines, tankers would be used. Transport costs were $2.75 per barrel for oil and $4.70 per barrel of oil equivalent (BOE) for gas.

Gulf of Mexico--Pipelines will be used to transport oil and gas to shore for processing at gulf coast facilities. If discovered reserves in the Eastern Gulf are too low to justify pipelines, tankers would be used. Transport costs were $0.50 per barrel for oil and $0.50 per BOE for gas in the shallow water portions of the Central and Western GOM; $1.25 per barrel for oil and per BOE for gas in the deep water portions of the Central and Western GOM and in shallow waters of the Eastern GOM; and $1.75 per barrel of oil and per BOE for gas in the deepwater Eastern GOM.

Pacific--Pipelines will generally be used to transport oil and gas to shore. Depending on location of landed oil, pipelines or tankers would be used to transport oil to refineries. If discovered resources are too low to justify pipelines, tankers would be used to transport oil directly to refineries. Transport costs ranged from $0.40 to $1.75 per barrel for oil and $2.10 to $6.32 per BOE for gas.

Alaska--Pipelines will be used to transport oil and gas to shore-based facilities. Oil will then be transported by tanker to west coast refineries. (If oil production from Alaskan OCS areas were to be shipped to the Gulf of Mexico for refining, its net economic value would decrease by about $0.75 per barrel.) Gas, on the other hand, would go to a liquefaction plant for processing and then be shipped via LNG tanker to a vaporizer in the Los Angeles area. Pipelines, terminal facilities, etc., would be shared by OCS planning areas whenever possible. Transport costs of Alaskan production to the west coast are shown in Table 12. (If each Alaskan OCS area were totally dependent on its own production to support pipelines and terminal facilities, transport cost for oil would increase by $5 or $6 per barrel over those listed in the table.) These assumptions for Alaskan transportation costs are for the 5-year program section 18 analysis only and should not be interpreted to reflect the actual transportation scenario which will be selected for future production.

TABLE 11

Representative Regional Discount Factors for Production and Revenue

Region	Water Depth	Production Discount Factor*	Revenue Discount Factor**
Gulf of Mexico	Shallow	0.362	0.410
	Deep	0.295	0.345
Pacific	Shallow	0.368	0.418
	Deep	0.295	0.345
Atlantic	Shallow	0.266	0.314
	Deep	0.228	0.276
Alaska	Shallow	0.150-0.243	0.190-0.293
	Deep	0.150-0.243	0.190-0.293

* Represents the ratio of the discounted value of gross production to the undiscounted value of gross production for constant real oil prices.

** Represents the ratio of the discounted value of gross production to the undiscounted value of gross production for oil prices increasing at 1 percent annually.

TABLE 11A

Representative Regional Production Profiles

Region	Water Depth	Years for Exploration and Delineation	Years from Delineation to Production	Build Up To Peak Production	Years at Peak	Maximum Years in Decline
Gulf of Mexico	Shallow	3	1	6	2	15
	Deep	7	1	6	2	15
Pa ific	Shallow	3	2	4	2	15
	Deep	7	1	6	2	15
Atlantic	Shallow	6	2	6	2	15
	Deep	6	4	6	2	15
Alaska	Shallow	7	5	6	2	15
	Deep	9	4	9	3	15

TABLE 12

TRANSPORTATION COST (1/87) TO THE WEST COAST (DOLLARS/BOE)

Alaskan Planning Area	Oil	Gas
Chukchi Sea	9.90	27.60
Beaufort Sea	6.60	27.60
Gulf of Alaska	4.40	19.85
Hope Basin	9.90	29.45
Kodiak	4.40	22.95
Cook Inlet	4.40	26.00
Navarin Basin	6.60	22.60
North Aleutian Basin	5.00	23.25
Norton Basin	6.60	26.00
Shumagin	5.00	23.85
St. George Basin	6.00	18.00

3. BOE (Oil and Gas) Prices

In establishing the starting landed prices of oil (i.e., refiners' acquisition cost), OCS crude oil was assumed to compete with imports. Initially, the starting landed prices of crude oil were derived from the average free on board world price weighted by export volume in July 1984, (see Weekly Petroleum Status Report, July 18, 1984). An additional charge for shipping costs (see DOE/EIA Monthly Energy Review) to the Gulf of Mexico was added to arrive at an adjusted landed price. This price was then further adjusted to account for the differences in the expected quality of OCS crude in the different regions versus imported crude to arrive at a quality adjusted landed price at the gulf coast in July 1984. Further adjustments for market factors were made to estimate a base case price at the west coast in July 1984. This price was adjusted to take into account price changes through the beginning of 1987.

As suggested by recent price changes, it is unlikely that the next several years will see a smooth balance of supply and demand which keeps prices stable. It appears more likely that periodic price fluctuations will become the norm. For example, in the spring of 1983, oil markets were seriously weakened and a dismified OPEC finally responded with a $5 per barrel price cut in the Saudi marker crude. To account for price fluctuations, both a low and high price scenario were developed and estimates made to determine the sensitivity of leasable resources to these price changes. For this proposed program analysis, a landed base case price (1984 dollars) of about $24 was used; roughly a $19 low and $29 high price scenario were also adopted. The lowered base case price scenario of $24 reflects decreases in oil prices which occurred over the past year and accompanying projections of a weaker oil market. (The $24 price is slightly higher than DRI's summer of 1985 estimate of $23.29 for imported oil (Data Resources Inc., Energy Review, Summer 1985, Table A-11, p. 170).) Adjustments were made to the 1984 prices by assuming constant prices through the end of 1984 and then beginning in 1985 to account for inflation at a 5-percent annual rate and oil price increases at a 1 percent real rate. The 5-percent annual inflation rate was chosen because DRI forecast average annual rates of change in the Wholesale Price Index between 1984 and 2010 ranging from a low of 3.1 to a high of 6.5 percent (DRI, Inc., Energy Review, Vol. 8, no. 3, Autumn 1984). Gas prices were derived from the landed oil prices by assuming Btu equivalent values.

For our analysis, the following area-specific price assumptions were made:

Atlantic and Gulf of Mexico--The east and gulf coast crude markets are dominated primarily by imports of relatively low sulfur (sweet) and high gravity (light) crudes. There is little difference in point-of-entry prices for a given quality of crude at the east and gulf coasts. The July 1984 export price of $28.65 was increased by $1.06 for transportation and by $0.64 for quality to arrive at an equivalent landed price of $30.35. This price was used in the high price scenario and actual prices of $25.35 and $20.35 were used for the base and low price cases. Adjusting for inflation and real price increases in 1985 and 1986, the January 1987 prices for the east and gulf coasts high, base, and low price case scenarios were $34.10, $28.50, and $22.85 per BOE, respectively.

West Coast and Alaska--The west coast market is dominated by higher sulfur (sour) and lower gravity (heavy) crudes from California, Alaska, and Indonesia. There is a significant difference in crude prices at the wellhead between California and Alaskan crudes because the latter must be transported via pipeline and tanker to the west or gulf coast refineries. After adjusting for transportation and API gravity, the export price of $28.65 became a July 1984 quality adjusted landed import price of $29.40 at the gulf coast. In estimating a west coast price for Pacific and Alaskan crude, the July 1984 price was decreased by $1.00 to account for the observed price differential between landed crude at the gulf and west coast markets, resulting in July 1984 price of $28.40. This price was used in the high price scenario; actual prices of $23.40 and $18.40 were used for the base and low price cases. After increases for inflation and real price growth in 1985 and 1986, the January 1987 prices for the west coast became $31.90 per BOE for the high case and $26.30 and $20.65 per BOE for the base and low price cases, respectively.

Note again that the base case oil prices for this draft of Appendix F are lower than those used previously due to declining oil prices during the ensuing year.

4. Discount Rates

In computing expected net economic values, real (annual) private and public discount rates of 6 and 8 percent were used. The private (after-tax) rate influences lessees' decisions on the magnitude and timing of exploration and development. A recent study on rates of return for OCS investments suggests that private after-tax real rates of return have been around 7 percent historically (W. J. Mead, P. E. Sorensen, et al., Additional Studies of Competition and Performance in OCS Oil and Gas Sales, 1954-1975, Final Report, USGS Contract No. 14-08-0001-18678, November 30, 1980).

Although the precise specification of the "correct" public discount rate is impossible, rates of 6- to 8-percent were used in our analyses. The 8 percent rate has been employed consistently in OCS program and tract specific evaluations since the late 1970's. Further, the 6- to 8-percent public discount rates:

1. Represent a reasonable range of returns to private investment and consumption spending.

2. Reflect the fact that OCS offerings do not mandate the replacement of private investment decisions with public selections.

3. Recognize that many public benefits of the OCS usually are unmeasured.

4. Correspond to recent reductions in the long-term cost of borrowing to the Treasury resulting from the substantial revenues generated by the program.

5. Represent the strong correspondence between public and private preferences in the pace of OCS leasing.

Table 13 lists net economic values per barrel (for leasable resources) and indicates their sensitivity to different discount rates and annual rates of oil price change. The table clearly indicates that higher net economic values per barrel are associated with lower discount rates. Using the base case (8 percent discount rate, 1 real price percent growth) assumptions for comparison, a 6 percent discount rate with 1 percent real growth would result in net economic values per barrel that are about 40 percent higher in the GOM and the Pacific, 70 percent higher in the Atlantic, and 90 percent higher in Alaska.

TABLE 13

Sensitivity of Net Economic Value per Barrel (1/87) for Leasable Resources to Discount Rate and Annual Oil Price Growth Rate Assumptions (Oil Price at $24 in July 1984)

Price Growth =	Discount Rate = 8%			Discount Rate = 6%		
	0%	1%	2%	0%	1%	2%
Planning Area						
Central Gulf of Mexico	4.41	5.84	7.49	6.33	8.25	10.48
Western Gulf of Mexico	3.70	5.13	6.78	5.44	7.36	9.59
Southern California	3.98	5.37	6.96	5.72	7.55	9.66
South Atlantic	1.91	3.28	4.92	3.54	5.50	7.84
Mid-Atlantic	1.25	2.63	4.24	2.63	4.52	6.74
Eastern Gulf of Mexico	2.38	3.81	5.46	3.79	5.71	7.94
Chukchi Sea	(0.08)	(1.03)*	(2.23)	(0.60)	(2.10)	(3.83)
Navarin Basin	0.69	1.94	3.42	1.67	3.42	5.49
Central California	3.21	4.60	6.19	4.77	6.60	8.71
Northern California	3.08	4.47	6.06	4.61	6.44	8.55
St. George Basin	0.17	1.42	2.90	1.01	2.76	4.83
North Atlantic	2.83	4.21	5.82	4.57	6.46	8.68
Beaufort Sea	0.48	1.36	2.76	0.92	2.67	4.87
Washington-Oregon	4.85	6.19	7.70	6.52	8.23	10.16
Gulf of Alaska	(-.61)	(0.58)*	(2.03)	(-.15)	(1.62)	(3.76)
North Aleutian Basin	(-.94)	(0.25)*	(1.70)	(-.60)	(1.17)	(3.31)
Norton Basin	(0.26)	(1.51)*	(2.99)	(1.13)	(2.88)	(4.95)
Kodiak	(0.06)	(1.25)*	(2.70)	(0.76)	(2.52)	(4.67)
Florida Straits	2.65	4.03	5.64	4.35	6.24	8.46
Hope Basin	(-.63)	(0.68)*	(2.25)	(-.02)	(1.85)	(4.09)
Shumagin	(0.15)	(1.34)*	(2.79)	(0.88)	(2.64)	(4.79)
Cook Inlet	(0.25)	(1.44)*	(2.89)	(1.01)	(2.77)	(4.92)

* The net economic value in parentheses in the 8 percent discount rate, 1 percent price growth case represents net economic value for a field in the planning area with an after-tax net present value equal to zero. This value is used because there are no positively valued fields in these areas at the $24 price. The net economic values in parentheses for the other cases are derived from the base case.

[Information in this attachment was developed after the 1983 National Energy Policy Plan was issued. This attachment and Appendix F, itself, will be revised once the 1985 National Energy Policy Plan is released. At that time, this attachment will be integrated into Appendix F.]

VIII. Alternative Energy Sources

A. Introduction

The U.S. economy has passed the peak of its reliance on domestic oil and gas resources. This general assessment is based on examination of historical data on energy production and consumption and on energy projections through the year 2000 (see Table F-_) prepared by the Department of Energy (DOE) as the Midrange Projections for the 1985 Energy Targets Report to the Congress as required by Title II of the Energy Security Act.

Oil and gas consumption began to substantially supplant coal about 1920, although this process was underway a few years earlier, a trend generally corresponding to expanding use of the automobile. Based on data from the Department of the Interior (DOI) publication Energy Perspectives 2, oil and gas combined edged past coal in total U.S. energy consumption in 1947, with 15.8 quads of coal consumption to 15.9 quads of oil and gas consumption. Oil alone surpassed coal in 1950, with 12.9 quads of coal consumption to 13.5 quads of oil consumption. (The term quads represents one quadrillion British thermal units of heat energy and is approximately equal to 172.4 million barrels of oil.)

In the late 1960's, close observers of energy issues in the Federal Government and other centers of interest began to try to call attention to a likely early peaking of ability to supply oil from domestic sources. Oil produced from Federal onshore leases peaked at 229.5 million barrels in 1969. Oil produced from all domestic sources peaked at 3,517 million barrels in 1970. Total domestic proved reserves also peaked in 1970. Oil produced from Federal leases on the Outer Continental Shelf (OCS) peaked at 455.5 million barrels in 1971.

At this point, oil imports increased very rapidly to fill the gap between declining domestic production and increasing energy supply requirements. Oil imports peaked at a rate of about 8.6 million barrels per day in 1977. Total oil supplied to the U.S. economy also peaked in 1977 at 18.5 million barrels per day, a level representing about 75 percent of total energy consumption.

Two major shocks to the world oil market focused public attention on oil supply issues. The 1973-74 Arab oil embargo cutoff Middle Eastern oil sources from unrestricted trade in world oil markets and resulted in escalation of oil prices from a pre-embargo world price of $7.74 per barrel in 1970 to a post-embargo price of $24.40 in 1975. The world oil market soon received a second major jolt during the 1979-80 Iranian revolution which once again reduced oil supply levels and accelerated prices to a 1980 world price of $42.36 per barrel.

ENERGY TARGETS 1/
(Quadrillion BTU's Per Year)

	1985 7/	1990	1995	2000
Domestic production:				
Crude oil and NGL 2/	21.1	19.0	18.5	18.1
Natural Gas 3/	18.0	18.5	17.5	16.5
Coal	19.8	22.5	25.5	29.3
Nuclear	4.1	5.9	6.6	6.8
Renewables and geothermal	6.0	7.0	8.8	10.5
Other	-	-	-	-
Subtotal 4/	69.0	73.1	76.9	81.2
Imports:				
Crude oil and refined petroleum	10.3	14.4	14.9	15.3
Natural gas	1.2	1.3	2.3	2.6
Coal 5/	(1.9)	(2.3)	(2.5)	(2.6)
Other 6/	0.1	0.2	0.3	0.3
Subtotal 4/	9.7	13.7	15.0	15.6
Total supply 4/	78.7	86.7	91.9	96.8
End-use consumption:				
Petroleum liquids	30.1	31.7	31.8	32.1
Natural gas	15.4	16.5	16.6	16.4
Direct coal	3.1	3.7	3.7	3.9
Electricity	7.9	9.1	10.3	11.6
Decentralized renewables	2.9	3.5	4.2	4.9
Other	-	-	-	-
Subtotal 4/	59.4	64.5	66.7	68.9
Conversion loss	19.2	22.2	25.2	27.9
Total consumption 4/	78.7	86.7	91.9	96.8

1/ Government-prescribed targets for energy production and consumption are inconsistent with the Administration's policy of allowing energy markets to determine energy demand and supply. Thus, these energy projections should not be seen as a description of what the Federal Government believes energy markets should do. The projections are very sensitive to assumptions about the future rate of economic growth and U.S. oil and gas resources. Varying these assumptions over reasonable ranges may affect individual projection values by plus or minus 20% or more. The projections for 1990 thru 2000 are from a draft study being developed in support of the 1985 National Energy Policy Plan and may be subject to minor revision.

2/ Includes oil shale, but does not include coal liquids.

3/ Does not include synthetic gas from coal.

4/ Totals may not add due to rounding.

5/ Brackets indicate net coal exports.

6/ Net electricity imports.

7/ 1985 projections are based on EIA data contained in, "Annual Energy Outlook-1984," DOE/EIA - 0383 (84), Jan. 1985.

In response to these events, the U.S. and the rest of the world instituted a wide variety of measures to conserve energy and to find alternative sources of supply. The overall success for these measures is best indicated by a decline in the world oil price in 1984 to about $29 per barrel. Oil prices have continued to decline and much of the analysis of various market and supply conditions contained in the Proposed Program has been at a price of $24 per barrel. Even lower prices are possible before longer term demand and supply conditions results in renewed price increases.

Subject to limitations of availability and price, oil and natural gas are projected to remain the fuels of choice in the U.S. economy. The rates of use in alternative fuels will be largely determined by factors such as success in finding new domestic oil and gas resources, political events affecting oil supplies from one or more of the major exporting nations, or technological breakthroughs related to costs of any of the major alternative energy sources. While current projections do not assume a general collapse in the ability of the Organization of Petroleum Exporting Countries (OPEC) to influence world production levels and prices, such an event does appear possible. An OPEC collapse would be expected to result in lower oil prices, reduced incentives for conservation, increased levels of oil imports, and lower outputs of alternative domestic fuels.

B. Oil and Gas

Production from domestic oil reserves has exceeded additions for about the last 15 years causing total proved reserves also to decline. The DOE did estimate an increase of 2.6 percent or about 711 million barrels in U.S. oil reserves in 1984. This was the first increase in reserves since 1970 when oil was discovered in Alaska's Prudhoe Bay. However, this increase is in part misleading as the 1984 estimates included substantial credit for anticipated application of enhanced oil recovery techniques in existing fields. The Energy Targets projections assume continued increases in costs of production and continued declines in overall domestic production. Higher oil prices are expected to make exploration of frontier and offshore areas more attractive. The net result of various behavior assumptions is long term decline in U.S. domestic production over the projection period from 21.1 quads in 1985 to 18.1 quads in 2000.

The overall rate at which new gas reserves are discovered is projected to decrease more rapidly than oil. Unconventional gas production is expected to respond to rising prices and to begin to offset natural reserve declines in the early 1990's. Overall, natural gas is projected to increase to 18.0 quads in 1985, to 19.0 quads in 1990, and to then begin a long term decline to the 2000 projection of 18.1 quads.

C. Coal

Coal is projected to increase in production more than any other fuel from 19.8 quads in 1985 to 29.3 quads in 2010. Major factors contributing to growth in coal production are expected to be growth in U.S. coal exports as well as increasing coal utilization in the U.S. economy. The chief uncertainty is to

what extent costs associated with the use of coal will reduce its capacity to compete in the marketplace. Ongoing studies to update the Energy Targets projections for the National Energy Policy Plan indicate that coal is the fuel most affected by changes in domestic energy market conditions.

Existing coal mines and coal transportation facilities are estimated to have the capacity to supply about 1.0 to 1.2 billion tons of coal per year (100-300 million tons, greater than estimated 1984 production). At this level, producers could supply the midrange coal production target through 1990 with little or no expansion of capacity. Over the longer term, as oil and gas resources are expected to increasingly fall short of market requirements, additional coal production capacity will be needed. Primary energy supply projections anticipate coal supplied energy at 22.5 quads in 1990, 25.5 quads in 1995, and 29.3 quads in 2000. The levels of production reached may vary widely in response to actual market conditions.

D. Nuclear

Nuclear power projections reflect slowdowns in plant construction, cancellation of plants under construction, and several years with no new plant orders. There is recognized to be a high degree of uncertainty regarding orders and construction times for new plants after 1990. The Administration has a variety of nuclear-related policy proposals directed toward Congressional action to reform the nuclear powerplant licensing process. Regulatory reform and public opinion on nuclear power are variables which complicate nuclear power projections beyond normal assessment of response to demand-supply-cost relationships. For purposes of comparison with other energy sources, midrange projections expressed in quads are 5.9 quads in 1990, 6.6 quads in 2000, and 6.8 quads in 2000.

E. Renewables and Geothermal

Recent rapid escalation in oil and gas prices set in motion powerful energy conservation forces as well as accelerating the search for alternative fuel sources. Given energy security problems in continued use of oil and gas and environmental problems which are widely recognized in coal and nuclear energy sources, a high level of public interest has focused on renewable energy sources.

Existing central-electric renewable energy production is primarily from hydroelectric generators. The U.S. is the world's leading generator or hydroelectric power. About 13.3 percent of total U.S. electricity generated in 1984 was from hydroelectric sources. Large scale hydro potential is limited by the availability of appropriate sites. Most new capacity is expected to come from retrofitting existing dams with new, larger equipment.

Geothermal energy is combined with hydroelectric power in the DOE analysis. Current utilization of the earth's internal heat is primarily through generation of electricity from natural steam at the Geysers site in northern California. In the future, other potential geothermal sources and technologies are likely to increase electric power generation. Other applications of geothermal energy such as space heating and industrial process heat also will increase.

The next form of energy expected to make a significant contribution to renewable energy use is wood. This use is limited, however, by wood availability and transportation costs. Wood utilization, therefore, is likely to be mostly in residential space heating and in the wood products industry which utilizes wood waste as a source of fuel.

Projected price increases for oil and gas in the 1990's are expected to stimulate large scale development of wind, photovoltaic, and solar central electric technologies. These technologies also offer high adaptability to dispersed use.

Renewable technologies are especially subject to uncertainties about future technological and economic factors. Overall, renewables are expected to advance from modest current use to a significant energy supply source by 2000. The overall renewable/geothermal domestic energy projection estimates of the Energy Targets Report indicate these sources increasing from 6.0 quads in 1985 to 7.0 quads in 1990, 8.8 quads in 1995, and 10.5 quads in 2000.

F. Conclusion

Oil imports which went up in 1984 for the first time since 1977 are projected to continue to increase. Crude oil and refined petroleum imports are projected to increase from 10.3 quads in 1985 to 14.4 quads in 1990, 14.9 quads in 1995, and 15.3 quads in 2000. OCS leasing is not expected to back out these levels of imports, but hopefully will allow the U.S. to avoid rapidly accelerated dependence which was typical of the early 1970's and which seriously threatened national security and healthy economic growth. While short term prospects are brightened by lower oil prices and excess world production capacity, the longer term view indicates the need to continue the concerted effort initiated following the 1973 oil embargo to use energy more efficiently, to find new domestic oil and gas resources, to diversify the sources of oil imports, and to learn how to best utilize alternative energy sources.

APPENDIX G

Estimates of Potential Social Costs of Developing the Oil and Gas Resources in Each OCS Planning Area

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I. Introduction, Summary and Conclusions

A. Background, Purpose, and Scope

Section 18(a)(3) of the Outer Continental Shelf Lands Act (OCSLA) provides that the timing and location of individual OCS lease sales be selected based on a consideration of balancing the potential for environmental damage, for the discovery of oil and gas, and for adverse impact on the coastal zone. Hence, an analysis of possible environmental damages and adverse coastal zone effects from proposed OCS oil and gas leasing is essential in order to evaluate the net social value (development benefits minus social costs) from this activity to the Nation and to each region involved with OCS hydrocarbon development.

This appendix, along with other information in the Secretarial Issue Document (SID), addresses the requirement set out in sections 18(a)(2) & (3) of the OCSLA by presenting an economic study for each planning area of the possible environmental damages and adverse impacts on the coastal zone associated with proposed and alternative five-year OCS oil and gas lease schedules. The estimates of potential damages are based on economic concepts and are given in dollar terms in order to provide a common basis for comparison with the estimated economic benefits from developing the leasable hydrocarbon resources in each OCS planning area. It is recognized, however, that some of the possible effects of OCS oil and gas leasing cannot be quantified in monetary terms, both because some issues are fundamentally not economic in nature and because the available information or the state of the art does not permit a quantitative assessment. Issues which cannot be addressed in quantitative terms will be discussed qualitatively in the environmental impact statement (EIS) accompanying the proposed five-year lease schedule as well as in Part II.B of the SID and Appendices H and I.

The purpose of this appendix is to attempt to quantify the possible costs of OCS oil and gas development to aid in the development of a lease schedule based on a consideration of a balancing of OCS benefits and costs. Given the specific program-level intent of the analysis, the economic review of the possible costs of OCS hydrocarbon development contained herein is carried out on an aggregated basis for each of the OCS planning areas. Detailed analysis of specific, intra-area resource management issues associated with a particular lease sale are beyond the scope of the present effort; these issues will be addressed in the five-year program EIS and in the EIS's and other management documents prepared in connection with individual, proposed lease sales.

B. The Concept of Costs Used in the Analysis

1. Introduction

Because the term "costs" can take on different meanings depending upon how it is used, it is important to state clearly at the outset the concept of costs used throughout this appendix. Two types of costs are estimated: social costs and regional costs. All costs are evaluated in terms of their present values. For this purpose, constant 1987 dollars and a real rate of discount of 8 percent are used.1/ The primary focus of the analysis which follows is on social costs.

2. Social Costs

Social costs measure the total costs to the Nation as a whole resulting from the proposed oil and gas development in each OCS planning area. The specific costs considered in the analysis of social cost encompass market and non-market costs and include: cleanup and control costs, direct and indirect commercial fisheries losses, tourism and recreation losses, infrastructure costs, ecological costs, subsistence losses, the value of lost oil and other costs.

Excluded from social costs are transfers, secondary (or "multiplier") effects and purely private costs. Transfers are merely financial redistributions. For example, oil spill-caused losses in a community's sales tax receipts are anticipated to be offset by increases in other communities' tax revenues. Because losses by one group are counterbalanced by gains to others, no net social cost is involved. Similarly, oil spill damage compensation payments redistribute the burden of a spill but do not change its social cost. Secondary effects usually are omitted from the estimation of social costs unless it is unreasonable to assume full employment and mobile resources, such as in isolated commercial fishing communities. Finally, purely private losses occur when, for example, a loss in profits by the tourist industry in one location is balanced by an increase in profits at substitute sites. Because the losses in one location are offset by gains at substitute sites, no social cost arises.

In all cost-benefit studies, the standard of comparison for assessing a policy is what would have happened in the absence of the policy. For this analysis, the with-vs.-without comparison is OCS oil and gas development vs. the alternative of imported oil. Hence, the social costs of the proposed five-year program must be measured net of the costs avoided because OCS oil development reduces the demand for foreign oil.2/

The national focus adopted for assessing social costs is important because it is consistent with the evaluation of the benefits of OCS development at the national level. Actual measurement of the social costs of production in an OCS area, however, requires that consideration be given to the consequences of that production for other OCS areas. For example, the analysis in later sections assumes that oil produced in the Navarin Basin is shipped south to refineries by tankers, potentially resulting in oil spills off all West Coast OCS areas thereby causing potential social costs in those areas. The social costs concerned, however, are attributed to OCS oil production in the Navarin Basin since they would not have occurred in the absence of the Navarin Basin production. On the other hand, oil production in an OCS area reduces social costs in other areas by backing out imported oil and foreign tanker spills. For example, oil produced in the Central Gulf of Mexico replaces an equivalent amount of imported oil destined for refineries in the Central Gulf of Mexico as well as other OCS areas. The reduction in imported oil means less oil will be spilled from foreign tankers in all areas concerned. Just as costs imposed on other areas are attributable to the producing OCS area, so too, the costs avoided when imported oil and the associated oil spillage are reduced also must be assigned to the producing area if social costs are to be measured correctly from the viewpoint of the Nation as a whole.

3. Regional Costs

In addition to an analysis of social costs to the entire Nation, the equitable sharing provision of the OCSLA dictates that the distribution of the potential social costs of OCS oil and gas development also be considered. To emphasize the important difference between the potential social costs to the Nation as a whole and the potential costs estimated to be realized by residents of the onshore area adjoining an OCS area, a second category of costs is estimated. These costs are referred to as regional costs.

Four factors determine the estimation of the costs associated with the development of hydrocarbon resources in an OCS area which are borne by the residents of the adjacent onshore area and hence constitute regional costs. First, the OCSLA provides for compensation to damaged parties for OCS-related oil spills and for commercial fishing gear losses. Payment of compensation to injured parties does not change the magnitude of social costs, but it does reduce the losses to area residents by redistributing the cost from the individuals suffering losses to a broader group within society as a whole. Second, as noted above, some tanker

spills resulting from OCS oil production in an area such as the Navarin basin impose costs on residents adjacent to other areas along tanker routes. Because any such costs are borne by residents of other areas, not by those residing adjacent to the producing area, these costs are not considered regional costs from the viewpoint of the residents adjacent to the producing area. (Of course, those suffering OCS-related tanker spill losses in any OCS area are eligible to receive compensation). The third factor determining the costs incurred by residents adjacent to an OCS area concerns the social costs avoided when OCS oil production replaces foreign oil which otherwise would have been delivered to that specific area. Since OCS oil production avoids spills from foreign tankers in areas with refineries, the associated social costs avoided must be considered when assessing the net costs of OCS production to the residents of the area. Fourth, shifts in economic activity that are costs to the residents adjacent to one area are benefits to another. Such shifts are not a national social cost but are a regional cost to the negatively affected OCS planning area. For example, a loss in tourism industry profits in an area affected by an oil spill will impose a regional cost; but since tourism industry losses will tend to be offset by gains in other OCS planning areas, no social cost occurs.

In summary, a proper estimation of the distribution of the costs of producing OCS oil, therefore, must recognize (1) the importance of compensation for damages, (2) costs falling outside OCS areas, (3) reduced oil spills from foreign tankers when OCS oil backs out imports, and (4) adjustments made for costs in one area which are offset by gains in other areas. These four factors are specifically considered in the estimate of the regional costs of producing and transporting all of the OCS leasable resources unleased as of January 1, 1987.

C. General Categories of Costs Considered

The costs examined in this appendix are those which could be incurred as a result of (1) oil spills in the marine environment, (2) physical conflicts among competing marine resource uses, and (3) other adverse coastal impacts. The third category includes (a) alteration of wetlands, (b) possible deterioration in air quality, (c) subsistence losses and (d) infrastructure costs.

A major focus of the analysis is on the costs of oil spills. Particular attention is given to the possibility of large oil spills -- those over 1,000 barrels. Spills of this size from OCS production are rare. A review of OCS oil spill data in the Gulf of Mexico, which accounts for over 85 percent of recent OCS oil production, indicates that no spills greater than 1,000 barrels have taken place since 1981; only three such spills have occurred from 1979 through 1984 (U.S. Dept. of Interior, 1983, p. 270; U.S. Dept. of Transportation, 1983, 1984). Nonetheless, large spills happen periodically, with potential serious damages, especially if they strike sensitive resources or reach shore within a few days, before natural weathering of the oil can reduce its harmful effects.

Small spills (those less than 1,000 barrels) also are considered in the analysis of social and regional costs. It should be noted, however, that although numerous, the total amount of oil discharged into the marine environment by small spills is relatively small compared to the total amount attributable to large spills. To illustrate, 934 small spills between 1 and 1,000 barrels constituted over 99 percent of all production platform and pipeline incidents recorded in the Gulf of Mexico from 1974 to 1983. However, these spills accounted for only about 28 percent of the volume of oil spilled during the period (U.S. Dept. of Interior, 1983, p. 270; Gail Rainey, personal communication, October 19, 1984). The average amount discharged in these small spills over the period cited was 9.4 barrels per spill.

The possible effects of drilling fluids on the marine environment are not considered in the analysis of potential costs. A recent report on this subject by the National Academy of Sciences (1983) concludes that drilling fluids discharged during exploratory operations, in general, do not pose a serious threat to the environment, although localized levels of pollution may be temporarily high and burial of benthic organisms in the vicinity of drilling operations could occur. The EIS prepared for the five-year program as well as sale-specific EIS's and the related management documents will address the issue of drilling fluids discharged during field development, to the extent potential environmental problems from this phase of OCS operations may exist in specific settings.

D. Overview of Methodology and Analytical Approach

1. Introduction

The object of this analysis is to estimate the present discounted value of the costs of OCS oil and

gas development for each planning area. To achieve this objective, the analysis proceeds through several steps. These steps are illustrated in the accompanying simplified flow chart (figure 1), and described in general terms below. A more detailed discussion of the analytical approach, assumptions and data used is presented in succeeding sections and attachments.

The two basic types of costs considered in this appendix are oil spill-related costs and non-spill costs. An overview of the approaches used to estimate each of these categories of costs follows.

2. Oil Spill Costs

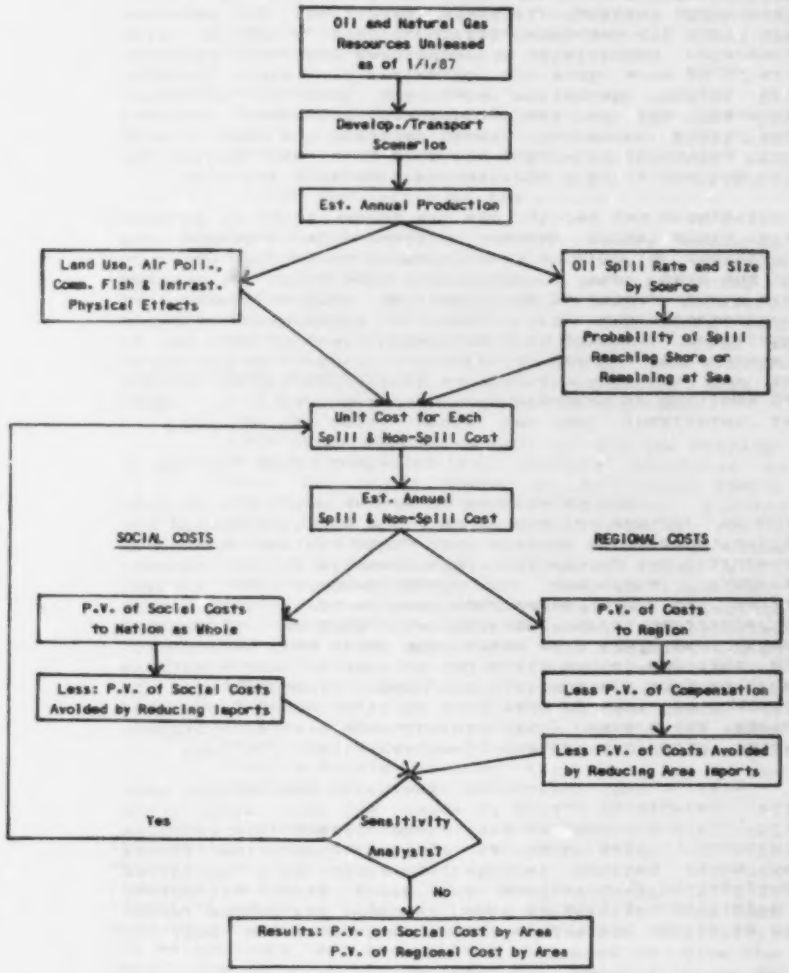
For each OCS area, estimated oil spill costs are determined by several factors. The principal factors include the scale of annual oil production; the estimated number (rate) of oil spills per unit of annual production; the estimated average size of spills; the chance that spills which do occur will strike land; and the marine resources and economic characteristics and the environmental productivity and sensitivity of each OCS area.

Estimates of the leasable oil resources unleased as of January 1, 1987 (see SID Table 1), and the development/transportation scenario (time to initial, peak, and final production; mode of oil transport) provide the point of departure for estimating each area's oil spill costs. The resource estimates used to estimate potential social and regional costs are those developed in Appendix F using the intermediate starting oil price assumption of $24 per barrel (see Appendix F, Table 8). Given this information, obtained from Interior Department sources, annual oil production is estimated for each OCS area using the procedure and information explained in Attachment A. The estimated resources and the development/transportation scenarios vary widely from OCS area to area; consequently, the estimated time pattern and rate of oil production differs considerably among OCS areas.

Using the estimated annual oil production for each

Figure 1

SIMPLIFIED
FLOW DIAGRAM FOR ANALYSIS OF SOCIAL
AND REGIONAL COSTS FOR EACH O.C.S. AREA



area, the rate (number) and size of large and small spills are established. The number of large spills (≥ 1,000 barrels) per billion barrels of oil for each source (production platforms, pipelines and tankers) is adopted from Lanfear and Amstutz (1983). Their results show that spill rates by source can be assumed to be the same for each area; this assumption also is incorporated in the analysis which follows. The estimated "typical" spill size for large platform and pipeline spills also is adopted from information on individual spills presented in Lanfear and Amstutz (1983). For vessels the large spill size is estimated from the worldwide tanker spill data file for the period 1974-1984 maintained by the Interior Department. Information for small spill sizes is based on the record of small spills in the Gulf of Mexico for 1974-1983. A detailed discussion of the sources and assumptions used to estimate spill rates and sizes is presented in Section III.A.1.

Given the estimated total spillage for each area, the next step is to estimate the amount of spilled oil expected to come ashore. This number is significant because, generally, the costs per barrel are considerably higher for spilled oil which comes ashore than for oil which remains at sea. The former requires costly onshore removal operations and imposes a variety of additional costs, such as recreation damages, not associated with spills which stay at sea.

The estimated probability that a spill will strike land, given that it occurs, is based on several hundred to two thousand oil spill trajectory runs made for each planning area as part of previous studies by the OCS oil spill modeling group in the Interior Department. Descriptions of the modeling approach used can be found in the appendix section of any sale specific EIS (e.g., Final EIS, OCS Sale No. 52, Appendix D) or in Smith, Slack, Wyant and Lanfear (1982). Since each of the several hundred individual oil spill trajectories is based on a specific area's likely resource locations, transportation routes and on historic data concerning prevailing winds and currents in the area, the probability figure used in this analysis can be regarded as a weighted average reflecting the overall chance that a given spill will come ashore. The model runs allow the expected amount of spilled oil thirty days to reach land. This is a highly conservative standard because spilled oil weathers considerably after only a few days. Spills which do not come ashore, of course, remain at sea. The results indicating the estimated amount of spillage to come ashore in each area play a key role in the subsequent analysis of costs.

Once OCS oil production and the amount of oil

spillage by year have been estimated, estimates of annual social and regional costs by area are developed. Basically, total costs are estimated by multiplying estimated unit costs per barrel spilled times the annual estimated spillage in each area. Constant marginal and average costs are assumed, for all oil spill costs, over the range of spills considered. All coefficients are expressed in constant 1987 dollars.

For oil spill-related costs, the unit cost coefficients developed in this study measure the costs reasonably expected to be incurred, by area, per barrel of oil spilled. These coefficients are adapted from available case studies of oil spill costs, modified by information from prior OCS lease sale EIS's and other sources. In general, the cost-per-barrel coefficients differ by (1) type of cost considered (e.g., oil spill control and cleanup costs vs. commercial fishery losses), (2) by planning area, reflecting the different resources, marine uses, and environmental sensitivity and productivity of each area, and (3) whether or not spilled oil comes ashore or remains at sea.

3. Non-oil spill costs

For non-oil spill costs, the cost coefficient is based on total OCS activity measured in billions of barrels of oil equivalent (BBOE), where natural gas is converted to equivalent barrels of oil.3/ For example, in the case of costs resulting from physical conflicts between commercial fishing and OCS hydrocarbon development or from alteration of wetlands, costs are assumed to begin one year after a lease sale and to increase until peak production in an area is achieved. For possible air quality losses, these costs are related to total annual oil and natural gas production.

Once the prospective unit costs of producing oil and natural gas in an area are estimated following the general approach outlined above, the total social and regional costs of developing all of the leasable resources in each area are estimated. Social and regional costs are evaluated for each area as if all unleased resources are leased as of a common reference date, January 1, 1987. For this purpose, all costs are assessed on the basis of their present discounted value. The use of present discounted values is essential because costs incurred within an area in different periods have different weights and can only be compared when a common yardstick is used -- here, the present discounted value of costs as of January 1, 1987. Use of present discounted values also permits an assessment of the net social value (development benefits minus social costs) of OCS oil and gas development by area in comparable dollar terms.

E. Sources of Information

Among the key sources of information used in this analysis are the following:

(1) Oil and gas resource information, development and transportation scenarios, oil spill trajectories, by area, and spill rates by source are based on extensive Interior Department analyses,

(2) Data on oil spill costs draws heavily on the findings of economic case studies of the cost of specific oil spills, modified by information from EIS's, the appendices on marine productivity and environmental sensitivity, and other sources to reflect the different characteristics of each OCS planning area, and

(3) Non-oil spill-related costs are adapted from estimates in the available literature.

Because the literature potentially applicable to the issues examined herein is so vast, considerable judgement was exercised concerning which and how studies could be used in the present effort. The large size and varied nature of the literature make it difficult to characterize. In general, however, particular attention was given to studies that were based on the same standard economic concepts employed in this analysis, were reasonably well documented, and were judged to be of reasonable quality. The specific sources of information consulted and used are documented in the text and summarized in the list of references.

F. Important Qualifications

Despite the fact that the best available information has been used in this analysis, the many uncertainties involved, the inherently difficult problems associated with measuring many social costs, and limitations in the state of the art are such that caution is required in using the numerical results. Moreover, in a number of cases quantitative analysis of issues simply is not possible.

As a result of the difficulties inherent in the measurement of social costs, when judgement was required concerning a cost estimate or an assumption to be used, a conservative, high-cost approach was adopted, provided a reasonable high cost estimate was available. Specific examples of this conservative approach include:

(1) Oil spills predicted by the oil spill trajectory model to reach shore may not actually strike land because of prevention measures (e.g., booms or at-sea recovery).

(2) Spills reaching shore may not impose tourism and recreation losses, depending upon the season in which spills occur and the speed and thoroughness of cleanup operations.

(3) In general, the actual per barrel cost of oil reaching shore may be lower than the cost per barrel figures based on the oil spill case studies used because the spills studied were very close to shore, allowing for relatively little weathering of the oil.

(4) Existing mitigating or regulatory measures, such as precluding the alteration of wetlands by shoreside pipelines or requiring a reduction in potential air pollution emissions, can reduce or eliminate many potential social costs (although costs of compliance are not considered here because they are production costs which are part of the net economic benefits calculations).

(5) Beneficial aspects of OCS oil and gas development are ignored. For example, platforms in some OCS areas serve as artificial reefs, improving the quality of recreational fishing (U.S. Dept. of Interior, MMS 84-0006, 1984). Also, offshore operators have provided emergency assistance to fishermen (see, e.g., Centaur Associates, Inc., 1984, pp. 266-268). Finally, additional OCS natural gas production to *some extent reduces the* amount of imported oil and the associated oil spills; and by substituting for other energy products, OCS natural gas production reduces air pollution problems (or air pollution control costs) in energy consuming areas. None of these beneficial effects, however, are considered in this analysis because they are beyond the scope of the present effort.

Notwithstanding the use of the best available information and assumptions which provide a high estimate of social and regional costs, informed judgement and simplifying assumptions necessarily play important roles in this analysis. Every effort has been made to document data sources and to state explicitly the methodology and assumptions employed to give the reader the opportunity to judge the reasonableness of

the results. Also, sensitivity analysis is used to examine how costs respond to variations in the estimates of unit costs and other estimates employed in the analysis. Non-quantifiable social costs are considered elsewhere in the Section 18 analysis. The EIS accompanying the proposed five-year schedule and the EIS's associated with specific lease sales discuss non-quantifiable issues in qualitative terms.

Finally, it is important to stress that the many uncertainties involved, the aggregated planning-area level of the analysis, and severe limitations in the state of the art for quantifying economic damages make it impossible to develop precise estimates of social costs or to present confidence intervals for these costs. Pre-sale estimates of hydrocarbon resources, their location and composition (oil or natural gas), the conditions under which any spills will occur and the damages which will result are all uncertain. Hence, in considering the results which follow, attention should be focused more on the relative ranking of planning areas than on the precise numerical results. Unless the results for planning areas differ by, say, a factor of 10 or 20, it may be unwarranted to conclude that social costs differ significantly between the areas.

G. Summary of Results for OCS Planning Areas

1. Introduction

Using the approach outlined above (and described in detail in succeeding sections), the present value of the potential social and regional costs from producing all leasable resources unleased as of January 1, 1987, have been estimated for each OCS area. Only the aggregated oil spill and non-spill cost results for each area are presented in this section. A more extensive summary of the results is contained in Section III.B.3, and a detailed listing of the individual oil spill and non-spill costs for each OCS area is presented in Attachments B and C. In addition, basic information and summary results for each OCS area are contained in Attachment D.

2. Summary of Estimated Potential Social Costs Results

Table I.G.1 summarizes the estimated potential social costs for each OCS area as a result of producing and transporting all of the estimated leasable oil and gas resources unleased as of January 1, 1987. Using the Western Gulf of Mexico as an example, the results in the table should be interpreted as described below.

The total gross present discounted value of the oil spill costs plus the non-oil spill costs for the Western Gulf of Mexico is $36.1 million in constant 1987 dollars (column 3 of Table I.G.1). This figure represents our best judgment of the total, quantifiable potential social costs resulting from the production and transportation of all of the area's resources. However, the potential social costs estimate of $36.1 million does not yet recognize the social costs avoided because oil from the Western Gulf of Mexico will back out imports in several coastal areas across the Nation, thereby reducing foreign tanker spills in those areas. Hence, the $36.1 potential social cost figure represents "gross" social costs.

The social costs avoided when Western Gulf of Mexico oil backs out imports is 6.7 million (Column 4 of Table I.G.1). After the social costs avoided are subtracted from gross social costs, we arrive at net social costs of $29.5 million for the Western Gulf of Mexico (Column 5). The $29.5 million is the estimated potential net social cost to the Nation as a whole of developing all of the Western Gulf of Mexico leasable oil and gas resources unleased as of January 1, 1987.

Estimated potential social costs range from $40.5 million for the Central Gulf of Mexico to less than $1 million for several Alaskan and lower 48 OCS areas (Table I.G.1). Generally speaking, there is a direct association between an area's total potential social cost and the total leasable hydrocarbon resources estimated to be contained in the area.

Total hydrocarbon resources alone, however, do not determine total potential social costs. The oil - gas resource composition, the transportation mode, the estimated chance that spills which occur will reach shore, together with the characteristics of an area's marine and coastal resources and environmental productivity and sensitivity also influence total social costs. For example, the Central Gulf of Mexico has total hydrocarbon resources which are essentially the same as, but potential social costs which are more than thirty percent greater than, the corresponding estimates for the Western Gulf of Mexico. One important reason for the large difference in social costs estimates for the two areas is that the Central Gulf of Mexico is expected to contain considerably more oil than the Western Gulf; hence, estimated oil spillage is greater for the former area. Other reasons for this large difference in the estimated total potential social costs between the two areas are that the Central Gulf has more valuable commercial fisheries, a higher environmental productivity and sensitivity ranking and is potentially more vulnerable

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Table 1.G.1

Summary of the Present Discounted Value of Estimated Potential Social Costs for Each OCS Planning Area (Millions of 1987 dollars)

AREA	(1) OIL SPILL COSTS	(2) NON SPILL COSTS	(3)=(1)+(2) GROSS SOCIAL COSTS	(4) LESS: COST AVOIDED FROM REDUCED IMPORTS*'	(5)=(3)-(4) TOTAL NET DISCOUNTED SOCIAL COSTS
CGOM	34.59	16.76	51.35	10.81	40.54
WESTGOM	17.64	18.49	36.13	6.68	29.46
S.CALIF	19.50	7.57	27.08	7.31	19.77
S.ATLAN	1.83	2.86	4.69	0.57	4.11
NAVARIN	21.28	6.90	28.17	3.34	24.83
EASTGOM	4.60	2.36	6.96	1.10	5.85
BEAUFRT	5.08	1.47	6.55	1.30	5.25
CHUKCHI	0.00	0.00	0.00	0.00	0.00
CEN.CALIF	5.68	2.92	8.60	2.35	6.25
N.CALIF	4.22	3.84	8.07	1.70	6.36
ST.GEORGE	1.11	2.13	3.24	0.34	2.91
MID-ATLAN	0.82	0.95	1.77	0.26	1.51
N.ATLAN	0.13	0.69	0.81	0.04	0.78
ORE/WASH	0.44	0.21	0.65	0.11	0.54
N.ALEUTIAN	0.00	0.00	0.00	0.00	0.00
GULFALASKA	0.00	0.00	0.00	0.00	0.00
NORTON	0.00	0.00	0.00	0.00	0.00
KODIAK	0.00	0.00	0.00	0.00	0.00
HOPE	0.00	0.00	0.00	0.00	0.00
SHUMAGIN	0.00	0.00	0.00	0.00	0.00
COOK INLET	0.00	0.00	0.00	0.00	0.00
STR OF FLOR	0.00	0.32	0.32	0.00	0.32

*' Estimated Potential Social costs avoided to the nation as a whole from reduced needs for imported oil, assuming reduced imports (and associated oil spills) are distributed across OCS planning areas in the same proportion as indicated in Table III.A.3.1.

to wetland alterations than the Western Gulf of Mexico (see Section II).

The net effect of all of the factors influencing social costs can be examined by assessing the social costs per unit of production--here measured as the potential social cost per billion barrels of oil--equivalent (BBOE) (Table I.G.2). Estimated potential social costs per BBOE range from $53.1 million for the Straits of Florida area to $6.4 million for the Western Gulf of Mexico and are not directly correlated with an area's total unleased resources.

The relatively high potential social cost per BBOE for the Straits of Florida ($53.1 million) is explained by a combination of possible wetland alterations and low resource estimates for this area. The use of a pipeline to transport natural gas from this area could alter some coastal wetlands. The extent of coastal wetland alteration is essentially a "fixed" cost because it depends primarily on the number of pipelines (one in this case) and is not very sensitive to changes in resource estimates. Because the resource estimate for this area is so low (.006 BBOE), the estimated social cost per BBOE is highly sensitive to fixed costs. Hence, for this reason, the potential social cost per BBOE for the Straits of Florida is quite high, even though estimated total potential social cost for this area is low.

The relatively high potential social cost per BBOE ($34.4 million) for the Navarin Basin is explained by possible infrastructure costs, the relatively high ratio of oil to gas resources (see Table III.A.1.1), and the transportation scenario for this OCS area. Other things equal, the higher an area's ratio of oil to gas, the greater the amount of estimated oil spillage per BBOE. Oil produced in this area is assumed to be shipped first by pipeline to a collection point, carried by tanker to Balboa Bay and then transported down the West Coast by tankers. Hence, oil produced in this area carries a double spill risk, since the oil is handled once by pipeline and twice by tankers. For these reasons, the estimated number of spills is large compared to other OCS areas, despite the relatively small amount of resources estimated for this area. The low potential social cost per BBOE for the Mid-Atlantic ($5.2 million) reflects the fact that the modest resources estimated for this area are all natural gas (Table III.A.1.1), so that potential oil spill costs do not arise.

One important factor determining the estimated social cost per BBOE is the estimated transportation

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Total and per BBOE net Estimated Potential Social Costs

	TOTAL NET SOCIAL COSTS	NET COSTS PER BBOE
STR OF FLORID	0.32	53.07
NAVARIN	24.83	34.39
N.ATLAN	0.78	22.19
NORTON	0.00	21.96
BEAUFRT	5.25	21.16
W.ALEUTIAN	0.00	18.24
ST.GEORGE	2.91	18.17
S.CALIF	19.77	15.93
CEN.CALIF	6.25	15.44
N.CALIF	6.36	15.37
KODIAK	0.00	15.33
GULFALASKA	0.00	14.49
EASTGON	5.85	14.07
CHUKCHI	0.00	13.24
CGON	40.54	8.70
WESTGON	29.46	6.36
S.ATLAN	4.11	6.45
MID-ATLAN	1.51	8.21
ORE/WASH	0.54	9.73
HOPE	0.00	7.64
SHUMAGIN	0.00	8.82
COOK INLET	0.00	27.61

mode for oil. Since tankers result in considerably more estimated oil spillage (74,695 barrels per BBO) than pipelines (41,449 per BBO), areas relying on tankers more than pipelines to transport oil will have higher potential social costs per BBOE, other things being the same.

The social cost estimates presented in Table I.G.1 differ markedly from the social cost estimates (called external costs) made in conjunction with the 1982 Secretarial Issue Document for the Tentative Proposed 5-Year OCS Leasing Schedule (Appendix 8). A detailed comparison of the approaches and the results of the estimation of social costs made in this Appendix with the approach and results of the social cost analysis carried out in the 1982 study is presented in Section I.H. and is not repeated here.

Regarding the composition of potential social costs, an important conclusion is that oil spill costs exceed non-oil spill costs for most OCS areas. For the lower 48 OCS planning areas, the most important potential oil spill social costs are cleanup and control, tourism and recreational, and ecological costs. For the Alaskan OCS areas, cleanup and control costs and ecological costs are the principal estimated potential oil spill costs.

For the non-oil spill costs, estimated potential wetland and air quality costs are the largest potential costs in this category for several OCS areas. Though small relative to total potential social cost for the Central and Western Gulf of Mexico and So. California OCS areas (see Attachment C). It is important to stress, however, that by regulatory authority the MMS limits air emission from OCS operations (or employs offsets) to avoid significantly affecting onshore ambient air quality. Furthermore, states through their permitting authority have considerable control over wetland use. For these reasons, non-oil spill costs may be overstated. Potential infrastructure costs (planning costs) could be relatively lrge for some areas, especially in remote Alaskan OCS areas and in Central and Northern California and for the Western Gulf of Mexico because of the major amount of unleased resources leasable as of January 1, 1987, for this OCS area.

3. Summary of Estimated Potential Regional Cost Estimates

As explained in Section I.B., the concept of regional costs is important when assessing the distribution of the potential costs of producing the hydrocarbon resources in each area. The concept of regional costs was introduced to indicate the estimated potential costs borne by residents of the states adjacent to each OCS planning area as a result of the production of all of the leasable resources unleased as of January 1, 1987. Table I.G.3 summarizes the estimated potential aggregate regional costs for each OCS area, using the unit cost assumptions developed in Section II. Extending our use of the Western Gulf of Mexico OCS area as an example, the information in Table I.G.3 should be interpreted as described below.

Note that the regional oil spill cost estimate (column 1 of Table I.G.3) typically exceeds the social cost estimate of oil spill costs (column 1 of Table I.G.1). For example, in the case of the Western Gulf of Mexico, potential regional oil spill costs are estimated to be $24.2 million, while oil spill social costs are only $17.6 million. The reason for this outcome is that while oil spills cause losses to a planning area's tourism industry, these losses tend to be offset by gains to the tourism industry in other areas as tourists are diverted to non-polluted, substitute recreational sites in those areas. Hence, tourism industry losses are regional costs but not social costs.

The OCSLA provides for compensation for OCS-related oil spills and for commercial fishing gear damages. Also, oil production in the Western Gulf of Mexico and in other OCS planning areas replaces imports of crude oil into the area, thereby reducing foreign tanker spills. An accurate assessment of potential costs to residents adjacent to this area, therefore, should be measured net of estimated compensation payments ($13.0 million) and net of the potential costs avoided by backing out foreign oil to this specific OCS area ($21.8 million).

The net potential regional cost for the Western Gulf of Mexico is $7.8 million in constant 1987 dollars. This figure represents our best estimate of the net potential costs incurred by residents near this OCS area as a consequence of producing and transporting all of the estimated leasable resources in all OCS planning areas unleased as of January 1, 1987. The figures for the other OCS areas should be interpreted in the same way.

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Table I.G.3 Estimated Potential Regional Costs by Area from Development of All Areas (Millions of 1987 Dollars)

AREA	(1) OIL SPILL COSTS IN REGION	(2) NON SPILL COSTS IN REGION	(3) COMPENSATION TO REGION	(4) IMPORT COSTS BACKED OUT OF REGION	(1)+(2)-(3)-(4) POTENTIAL NET COSTS TO THE REGION
S. CALIF	26.72	7.57	13.90	2.65	17.74
NAVARIN	17.49	6.90	8.96	0.00	15.42
CGON	45.44	16.76	23.71	28.13	10.36
WESTGON	24.18	18.49	13.03	21.82	7.81
N. CALIF	6.46	3.84	3.39	0.00	6.91
CEN. CALIF	8.62	2.92	4.46	0.76	6.32
EASTGON	6.05	2.36	3.10	0.12	5.20
S. ATLAN	2.12	2.86	1.28	0.26	3.43
BEAUFRT	3.26	1.47	1.70	0.00	3.03
ST. GEORGE	0.71	2.13	0.40	0.00	2.44
ORE/WASH	2.76	0.21	1.40	0.93	0.65
N. ATLAN	0.15	0.69	0.08	0.32	0.43
STR OF FLOR	0.00	0.32	0.00	0.04	0.27
CHUKCHI	0.00	0.00	0.00	0.00	0.00
N. ALEUTIAN	0.00	0.00	0.00	0.00	0.00
GULFALASKA	0.00	0.00	0.00	0.00	0.00
NORTON	0.00	0.00	0.00	0.00	0.00
KODIAK	0.00	0.00	0.00	0.00	0.00
HOPE	0.00	0.00	0.00	0.00	0.00
SHUMAGIN	0.00	0.00	0.00	0.00	0.00
COOK INLET	0.00	0.00	0.00	0.00	0.00
MID-ATLAN	0.99	0.95	0.56	3.79	-2.42

4. Social Cost Sensitivity Analysis

In recognition of the many uncertainties and inherent difficulties involved in the estimation of social costs, three types of sensitivity analyses were carried out to determine the magnitude of area potential social cost changes in response to changes in key variables used in the analysis. The first sensitivity analysis examined how area social cost estimates might be altered if specific unit costs are presumed to be even higher than the conservative (i.e., high estimate) costs developed in Section II. Wetlands, ecological and commercial fishing industry losses were selected for the sensitivity analyses because these costs are potentially quantitatively significant and inherently difficult to estimate. Even the extreme sensitivity analysis case considered -- where wetland acres altered, ecological costs and commercial fishing industry losses were all assumed to be 50 percent greater than the unit estimates developed in Section II -- leads to a less than 30 percent increase in estimated potential social costs. This is because (1) only a subset of all costs increase, and (2) the social costs savings from backing out imported oil also increase, thereby moderating the net increase in potential social costs. The results of the extreme sensitivity analysis indicate that while the potential costs in each case considered are greater than the base case results presented in Table 1.G.1, the ranking of ten major OCS areas by their potential social costs does not change (see Table III.B.2.5).

The second set of sensitivity analyses examined how the estimates of potential social costs, net of costs avoided by reducing imports, could change when the average size of large oil spills is reduced. If only the average spill size used for domestic tankers carrying OCS oil is lowered, all else remaining the same, then the estimates of potential social costs decline for areas which will transport oil by vessel vs. pipelines (see Table III.B.2.5). This happens because less oil is spilled as a consequence of transporting oil by tanker when the average tanker spill size declines. On the other hand, if the average spill size is lowered for both domestic vessels carrying OCS oil and for foreign tankers delivering imported oil, then the net social cost declines for areas using tankers to move OCS oil but increases for areas transporting OCS oil by pipeline (see Table III.B.2.6). This result occurs because reducing the size of foreign tanker spills lowers the social cost

avoided by backing out a given amount of imported oil. It follows that the social costs avoided by backing out imports declines and therefore the net social costs for an area increase. The sensitivity analyses are described in detail in section III.B.2.

A third set of sensitivity analyses evaluated how the estimated potential social costs for each OCS planning area could vary in response to a change in the quantity of leasable resources estimated for each area in response to the use of alternative starting prices for oil. The low resource case was based on the resource estimates developed in Appendix F at a starting price for oil of $15 per barrel, while the high resource case used a starting oil price of $29 a barrel (see Appendix F, Table 6).

As expected, relative to the social costs estimated in the base case (Table 1.G.1), the low resource sensitivity case resulted in generally lower estimates of potential social costs, while the high resource estimate case typically resulted in higher estimates of potential social costs (see Tables III.B.2.7 and III.B.2.8). The variation in social cost among areas was notable for the Alaskan OCS areas and for the No. Atlantic area. For these areas, the resource estimates are sensitive to initial oil price changes over the range of starting oil prices considered. However, estimates of potential social costs do not change substantially for some OCS areas, notably the Central and Western Gulf of Mexico and So. California, when the starting price of oil is varied. The reason for this outcome is that the leasable resources estimated for these OCS areas are not highly sensitive to the price changes considered (see Appendix F, Table 6).

H. Comparison With Results of Prior Section 18 Analysis of Social Costs (External Costs)

The analysis in this appendix differs from that carried out in 1982 in several important respects. In general, the present analysis uses updated, much lower oil and gas resource estimates and more recent oil spill rates and economic and other information than was employed in the 1982 study. In addition, the analysis carried out here, building upon the experience gained in the 1982 exercise, considerably extends and refines in a number of ways the previous study of social costs (called external costs in 1982). The overall effect of using updated resource assumptions and other data and refined concepts and techniques is (1) to increase the estimated potential social costs of developing the oil and gas resources of the Central and Western Gulf of Mexico and (2) to decrease the potential costs of

developing the hydrocarbon resources in other areas. A summary comparison of the 1982 and the 1987 resource estimates and the estimated potential social costs, for each OCS area, is presented in Table I.H.1. The following five factors explain, in part, the differences between the 1982 and the 1987 estimates of potential social costs.

1. For every OCS area, the estimates of leasable resources used in this analysis are considerably lower than those used in the 1982 study of potential social costs. For example, for the Central Gulf of Mexico, the area with the highest hydrocarbon potential in 1982 and the second highest in 1987, the 1987 resource estimate is about 50 percent of the resource estimate made in 1982. The 1987 resource estimates for the North Atlantic and the Beaufort Sea are only a very small fraction of the 1982 resource estimates for these areas (Table I.H.1).

The lower 1987 resource estimates reflect the leasing of resources since 1982, updated geologic information acquired as a result of drilling activity during the intervening period and trends in prices, potential costs, drilling depths and related factors. Other things being the same, lower resource estimates lead to lower estimates of potential social and regional costs.

2. The oil spill rates for large spills for each source used in this analysis differ from those adopted in 1982. This is an especially important consideration for oil transported by tanker. The 1982 study used an estimated tanker spill rate of 3.87 large spills per billion barrels of oil transported. In comparison, this analysis uses a tanker spill rate of 1.3 spills per billion barrels, based on the updated results of the statistical analysis of oil spills by Lanzear and Amstutz (1983) which became available subsequent to publication of the 1982 study. Also, the analysis in this appendix uses an estimated average spill size of 57,458 barrels for tanker spills, based on the average size of worldwide vessel spills over 1,000 barrels during the period 1974-1984. In contrast, the 1982 study used an average tanker spill size of 230,000 barrels. A comparison of the 1982 and 1987 oil spill rates and spill sizes, for each source, is presented in Table I.H.2.

One effect of using considerably lower spill rates for tankers and a very substantially lower average spill size for tanker spills is to lower the potential gross social and regional costs of OCS hydrocarbon development relative to what they would be had the 1982 tanker spill rate and average spill size been used. The

Table I.H.1. Comparison of Estimates of Resources and Estimated Potential Social Costs for 1982 and 1987b for Each Planning Areaa/ (dollar figures in millions of $1987)b/

Area	1982 Resources (BBOE)	1982 Social Cost	1987 Resources (BBOE)	1987 Social Cost
Central Gulf of Mexico	9.5	-$1,141	4.7	$46
Western Gulf of Mexico	6.1	- 558	4.6	30
So. California (1982)a/	2.3	496	---	--
So. California (1987)a/	---	---	1.2	20
Beaufort Sea	5.4	2,665	.3	5
Cent. & No. California (1982)a/	1.2	570	---	--
Cent. California (1987)a/	---	---	.4	6
No. California (1986)a/	---	---	.4	6
So. Atlantic	1.6	471	.6	4
Navarin Basin	1.9	558	.7	25
Mid-Atlantic (Old)	4.7	157	.2	1
East Gulf of Mexico	1.2	856	.4	6
St. George	0.9	422	.2	3
Ore.-Wash.	---	---	.1	1
No. Atlantic	7.0	223	neg.c/	1
Straits of Florida				neg.c/
No. Aleutian	0.4	174	neg.c/	neg.c/
Gulf of Alaska	0.7	335	neg.c/	neg.c/
Norton	0.4	149	neg.c/	neg.c/
Kodiak	0.7	310	neg.c/	neg.c/
Chukchi Sea	1.3	661	neg.c/	neg.c/
Shumagin	0.2	74	neg.c/	neg.c/
Hope	0.1	12	neg.c/	neg.c/
Cook Inlet	0.2	1	neg.c/	neg.c/

a/Because the OCS area boundaries differ in some cases between the two periods, all areas may not exactly correspond.

b/1982 dollar values converted to 1987 dollars using the GNP implicit price deflator.

c/neg. = negligible: less than .1 BBOE or $1 million.

Table I.H.2. Comparison of 1982 and 1987 Oil Spill Rates and Sizes for Large Spills (equal to or greater than 1,000 bbls) for Each Source a/

Source	Estimated number of spills per BBO		Average spill size (equal to or greater than 1,000 bbls)	
	1982	1987	1982	1987
Platforms	0.79	1.0	21,000	18,378
Pipelines	1.82	1.6	26,000	25,937
Tankers	3.87	1.3	230,000	57,458

a/The 1982 spill rates and sizes are taken from the 1982 Secretarial Issues Document for the Tentative Proposed 5-Year OCS Leasing Program, Appendix B, pp. 5-6. The sources for the 1987 spill rates and sizes are described in the text.

net effect, however, is to increase the estimates of potential social and regional costs. This seemingly inconsistent result occurs because the potential social cost savings resulting from reduced import-related oil spills is considerably smaller when the latest tanker spill statistics are used.

The impact of using the updated, generally lower (except for platforms) spill rates and sizes can best be illustrated with an example. Consider a hypothetical OCS area with 400 million barrels of leasable oil resources, 75 percent of which will be delivered to refineries by pipeline, 25 percent by tankers. All OCS oil is assumed to replace imported oil on a barrel-for-barrel basis. Foreign tankers are assumed to have the same spill rate and spill size as domestic tankers. However, one half of foreign tanker spillage is assumed to occur outside United States waters.

Using the spill rates and sizes indicated in Table I.H.2, the estimated spillage from OCS production and transportation employing the 1982 rates is 81,067 barrels greater (109,842-28,775) than the estimated spillage obtained using the 1987 rates (Table I.H.3). Hence, for given oil resources, a given transportation scenario using pipeline and tankers and given unit oil spill costs, the 1987 spill rates lead to substantially lower oil spill costs than does use of the 1982 spill rates and sizes.

On the other hand, social costs to the Nation as a whole are measured net of the social costs avoided when imports are backed out by OCS production. Because the 1982 study of social costs used high spill rates and a very large average spill size for tankers, the example results indicate that a substantial amount of oil spillage from foreign tankers was avoided (178,020 barrels) because OCS oil production (primarily transported by pipelines) replaced imports. In fact, the net effect of replacing imported oil with OCS production using the 1982 spill rates is to lead to a net reduction in the total amount of oil discharged into domestic waters of 68,178 barrels (109,842-178,020) when both OCS operations and backed out imports are considered. Thus, the overall effect of using the 1982 rates in this example is to lead to a substantial social cost savings -- which was, in fact, the result obtained for the Central and Western Gulf of Mexico OCS areas in 1982 (see Table I.H.1).

To make the same point another way, the lower 1987 oil spill sizes and spill rates result in substantially smaller estimated discharges from OCS production and transportation (28,775 barrels spilled vs. 109,842 barrels using the 1982 rates). Hence, if all other

Table I.H.3. Comparison of Estimated Oil Spillage from a Hypothetical OCS Area Using the 1982 and 1987 Spill Rates and Sizes.
Assumed area resources: .4 Billion Barrels of Oil
Assumed transport modes: 75% pipeline, 25% tanker

Source	Estimated Spillage Using Spill Rates & Sizes Applicable in:a/		Difference
	1982	1987	(1982-1987)
Platform	6,636	7,351	(715)
Pipeline	14,196	12,450	1,746
Tankers	89,010	7,470	81,540
Small Spills	0	1,504	(1,504)
Total from OCS production & transportation	109,842	28,775	81,067
Less: Spillage avoided by reducing imports	178,020	14,939	163,081
Total	-68,178	13,836	(82,014)

a/From Table I.H.2

factors are the same (resources, transport mix, unit oil spill costs), the 1987 spill rates and sizes lead to substantially lower estimated social costs resulting from OCS operations. However, the social costs avoided by reducing the amount of imported oil -- 163,081 fewer barrels of oil are spilled from foreign tankers in this example -- also is lower when the 1987 oil spill rates and sizes are used rather than those used in 1982. Therefore, the overall estimated amount of oil spillage, taking into account both OCS production and backed out imports, is higher when the 1987 vs. the 1982 oil spill rates and sizes are used (13,836 vs. -68,178 in Table I.H.3). The fact that the spill rates and sizes used in this analysis are lower than those used in 1982 explains why the social cost estimates for the Central and Western Gulf of Mexico are positive in 1987, although they were negative (indicating a savings) in 1982. (Table I.H.1)

The effects of using different spill rates and sizes in 1982 and 1987 vary from OCS area to area, depending upon the amount of resources, the oil-gas composition of the resources, the extent to which pipelines vs. tankers are used. The computer model developed as part of this analysis has been used to analyze the interaction of these and other factors.

3. This appendix employs a stricter definition of costs based on economic concepts than was used in 1982. For example, the 1982 study employed the 'life support' concept which involves use of a net energy analysis to evaluate wetland losses. This approach resulted in an estimated loss per acre of about $114.1 thousand (in 1987 dollars), assumed to be constant across all OCS areas. However useful the concept may be for scientific studies, there is no economic justification for using the life support approach to estimate economic losses from wetland alterations (Shabman and Batie, 1978). In contrast, this study uses a 'components' approach for valuing wetlands damages, whereby an explicit effort is made to account for individual, area-specific benefits foregone when wetlands are altered.

The effect of using the components approach to value wetland alterations is to lower wetland damages per acre compared to what would have been estimated using the 1982 approach. Nonetheless, the approach used in this appendix is believed to provide a conservative (i.e., high) wetland damage estimate because, among other reasons, individual states and the Federal government have considerable authority to control wetland losses (see Section II.B.2).

4. A number of costs not considered in the 1982 study are included in this appendix (e.g., commercial

fisheries area preemption and gear conflict losses and secondary (multiplier) losses from commercial fishing oil spill losses). Also in this appendix, costs are estimated on a more area-specific basis than was the case in the 1982 effort. For example, wetland losses and commercial fishing losses and associated secondary effects are geographically disaggregated to reflect differences among OCS areas; and oil spill cleanup and control costs are recognized to be higher for Alaska than for the 'lower 48'.

5. Another refinement in the present analysis of social costs is that a procedure is developed to estimate annual production of the unleased resources in each area, given the development timing scenarios (time to initial and peak production, peak production as a percent of total production, and total production period) estimated by the MMS for each area. The use of this procedure, explained in Attachment A, allows one to estimate potential social and regional costs on an annual basis. In contrast, the 1982 study used highly simplified assumptions to estimate the timing of costs (e.g., all oil spills and spill damages were assumed to occur three years after initial production in each area, and air pollution damages were based on an assumed, constant production per year). On balance, the effect of this new, more reasonable approach for estimating annual potential costs is to lower the present discounted value of the potential costs of OCS production, relative to what the estimates would have been using the highly simplified 1982 approach.

II. Development of Unit Cost Estimates

A. Estimates of Potential Oil Spill Costs

1. Control and Cleanup Costs

Oil spill control and cleanup costs are comprised of the opportunity cost of the resources employed in control and cleanup operations. Market prices are good indicators of opportunity costs for most resources employed in control and cleanup operations, but evaluation problems arise when government resources or volunteers are used or when long-lived equipment is purchased to respond to a particular spill (Anderson, Conger and Meade, 1983). Control and cleanup costs typically represent the single largest market valued cost of a spill, often accounting for fifty percent or more of its total cost. Hence, this category of costs merits special attention.

The costs considered here include the cost of manpower, equipment, supplies and services used: (1) to

stem the loss of oil from a tanker, pipeline, or offshore oil facility, (2) to recover the oil at sea or prevent it from reaching shore, and (3) to remove and recover the oil, should the spill come ashore. The costs of any damages or restoration of the environment, however, are not considered here and are taken up in later sections of this analysis.

Table II.A.1.1 summarizes information from several major spills reported in the literature. Although some additional information is available concerning cleanup costs for other spills (see, e.g., Organization for Economic Cooperation and Economic Development, 1982), the spills cited are the most relevant for this report because they are reasonably documented and are based on the same conventional economic concepts as employed in this analysis.

Several factors influence the per barrel cost of controlling and cleaning up a particular spill. As the results in Table II.A.1.1 indicate, whether or not a spill strikes shore is a very important determinant of the per barrel cost of controlling and cleaning up a spill. For spills which did hit land, the average per barrel cost in 1987 dollars was $228, while for the one spill which remained at sea, the cost per barrel amounted to $22. Because there is such a major difference in cost per barrel between spills which do and which do not hit land, later in this analysis considerable attention will be given to the estimated chance that spills in an OCS planning area will or will not strike shore.

The geographic location of an oil spill also will influence control and cleanup costs in some cases because of relative cost differences among regions. In particular, control and cleanup costs for a spill on the Alaskan OCS likely will be considerably higher than for a spill on the "lower 48" OCS, all else being equal. To allow for possible higher costs, Alaskan OCS cleanup and control costs are assumed to be 45 percent greater than for lower 48 OCS oil spills, based on the F.W. Dodge labor and materials construction cost index for Anchorage (L. A. McMahon, 1983, p.XII).

Control and cleanup costs also are affected by such considerations as the type of shoreline struck (e.g., sandy beach vs. rocky shore) and by the ease of accessibility of the resources employed in cleanup operations to the spill area. However, sufficient historic data do not exist to isolate the effect of these (and possibly other) factors on control and cleanup costs. Moreover, at the level of aggregation necessarily used in this document, it is not feasible to predict precisely the specific sections of areas

Table II.A.1.1 Control and Cleanup Costs

Spill	Location	Year	Cost in $ Millions Current	Cost in $ Millions 1987a/	Barrels (thousands)b/	Cost Per barrel 1987 dollars
Reached Shore						
Zoe Colocotroni	Puerto Rico	1973	7.3c/	18.1	36	505
Amoco Cadiz	France	1978	106-117d/	186.3-205.7	1,600	116-128
Santa Barbara	United States	1969	10.5e/	31.9	77	405
STC-101	United States	1976	0.6f/	1.2	6	205
Torrey Canyon	Great Britain & France	1967	21.2g/	70.6	858	82
Ixtoc I	Mexico & U.S.	1979	120.3h/,i/	194.1	5,000	39
Remained at Sea						
Argo Merchant	United States	1976	1.9f/	3.8	179	21

a/Using GNP implicit price index.

b/Conversion ratios used are: 42 gallons = 1 barrel and 1 metric ton = 7.33 barrels.

c/Sorensen (1977, p. 3).

d/U.S. Dept. of Commerce, NOAA (1983, p. 143).

e/Mead and Sorensen (1970, p. 225).

f/U.S. Comptroller General, General Accounting Office (1977, App. I, pp. 7-8).

g/Burrows, Rowley, and Owen (1974, p. 241).

h/U.S. Dept. of Interior, Bureau of Land Management (April, 1984, Vol. II, p. 14).

i/Excludes the value of the lost semi-submersible drilling rig ($33.4 million 1987 dollars).

that could be affected by a spill, should one occur. For these reasons, in the calculations made later, the only distinctions made when estimating cleanup and control costs for possible spills in the different OCS planning areas are: (1) whether or not the spill is expected to come ashore, (2) whether the source of the spill is an OCS production platform, pipeline, or a tanker, and (3) whether the spill is on the lower 48 OCS or the Alaskan OCS. No specific allowance is made for the influences of other factors on per barrel control and cleanup costs, except insofar as the use of an average from historic data implicitly reflects other determinants of cost. The per barrel cost of controlling and cleaning up oil spills used in the subsequent analysis of costs ranges from $327 for a spill coming ashore from an Alaskan OCS platform to $21.5 per barrel for an OCS-related tanker spill in the lower 48 which remains at sea (Table II.A.1.2).

2. Commercial Fisheries Losses

Direct Effects. Several types of losses could result should an oil spill occur and affect areas important to commercial fisheries. Spills which threaten fishing harbors can prevent vessels from leaving port for an extended period. Unless subsequent fishing effort yields returns sufficiently great to compensate for the lost fishing time, losses will be realized by the affected fishing fleet. If a spill strikes shore, the owners and employees of aquaculture, ocean ranching, or shellfish holding tank facilities could realize losses, although these losses can be reduced by defensive measures. Furthermore, costs arise if fishermen incur extra expenditures to remove oil coating vessel hulls and gear.

Costs also will be realized in open-sea fisheries if adult fish are damaged by the spill or if fish stocks are dispersed, thereby raising search costs. Long-term losses could occur if a spill damages susceptible eggs and larvae or coastal nursery areas, although these effects typically are difficult to assess because of the wide natural variations in fish stocks and the lack of definitive biological data.

Only direct commercial fisheries losses related to oil spills are considered here. Possible long-term effects on commercial fisheries caused by damages to lower trophic, non-commercial organisms or loss of wetland areas also could occur; these losses are considered later under potential ecological costs and value of lost wetlands. Potential losses to commercial fishing from at-sea physical space use conflicts with oil and gas facilities, and gear damage attributable to OCS-related debris and bottom obstructions, are covered

Table II.A.1.2. Summary of Per Barrel Oil Spill Control and Cleanup Costs Used in Analysis of OCS Planning Areas

Spill Type	Cost per Barrel Lower 48 ($1987)	Cost per Barrel Alaskan OCS ($1987)a/
Production Platform		
Hits shore	225b/	326
Remains at sea	102c/	149
Pipeline		
Hits shore	222d/	321
Remains at sea	62d/	91
Tanker		
Hits shore	228b/	331
Remains at sea	22e/	32

a/Unit cleanup and control costs for the Alaskan OCS are assumed to be 45 percent greater than indicated costs for lower 48 OCS spills, based on F.W. Dodge labor and materials construction cost index for Anchorage (L.A. McMahon, 1984 Dodge guide to Public Works and Heavy Construction Costs, 1983, p. XII).

b/Average of the cost of the relevant spills in Table II.A.1.1.

c/Estimate based on average per barrel well control costs for two production spills reported in Table II.A.1.1 ($81) plus the per barrel at-sea control and cleanup costs for the ARGO MERCHANT ($21).

d/Average of platform and tanker costs.

e/ARGO MERCHANT spill.

in later sections. Secondary (multiplier) effects are examined immediately following this section.

The most carefully documented economic analyses of the impact of oil spills on commercial fisheries are the studies of the Santa Barbara platform spill of 1969 and the supertanker AMOCO CADIZ oil spill of 1978. In the Santa Barbara spill, the loss of about 79 thousand barrels from the Union Oil Co. platform threatened to pollute a nearby fishing harbor. The booms used to prevent the oil from entering the harbor precluded the 75 fishing vessels in the port from fishing for a period of two months. The estimated loss in returns on capital to the vessel owners and the loss in labor payments to the crews made unemployed amounted to $2.1 million (in 1987 dollars). Fishing vessel cleanup costs of $0.72 million also were incurred.

The 1.6 million barrels of oil lost in the AMOCO CADIZ spill polluted some 240 miles of the French coast. Over the 21-month post-spill period studied, the estimated loss to open-sea fisheries of $8.2 million in 1986 dollars was greatly exceeded by losses suffered by the area's major oyster culturing operators, $42.7 million (in 1987 dollars). Costs to the owners of large shellfish holding tanks affected by the spill totalled $4.6 million, and the cost of cleaning some 371 fishing vessels in the 13 ports affected by the oil spill was estimated to be $0.51 million (in 1987 dollars).

An important feature of both the Santa Barbara and the AMOCO CADIZ spills is that they took place close to land, and prevailing currents and winds combined to drive a considerable amount of the spilled oil to shore after only a brief period. Hence, relatively unweathered oil posed a considerable threat to fisheries and to fishing facilities. Damage to commercial fisheries from oil spills remaining at sea, however, are considerably less well documented. In fact, studies following the loss of 179 thousand barrels of #6 oil in the 1976 ARGO MERCHANT oil spill off Massachusetts were not able to identify any losses to commercial fishing as a result of the spill, although the possibility of long-term effects on commercial fisheries because of impacts on fish eggs and larvae and on the food web were recognized (Sherman and Busch, 1978, p.160)4/

The per barrel cost (in 1987 dollars) to commercial fisheries of the AMOCO CADIZ ($35.1) and the Santa Barbara ($36.1) oil spills was approximately the same. However, the potential cost to commercial fisheries from oil spills in other OCS areas depends upon the value and characteristics of the fisheries concerned, the relative threat posed to fisheries by

possible oil spills (the expected number of spills, their timing and trajectories), and other factors.

Recognizing that the risk to commercial fisheries varies across OCS areas, a basic loss-per-barrel-spilled figure of $36 is used (the rough average for the Santa Barbara and AMOCO CADIZ spills); but this basic figure is adjusted by area based on the ratio of the value of landings in each area to the value of landings in the Santa Barbara planning area (Southern California). Thus, if an area has landings worth 20 percent more than Southern California, the loss-per-barrel-spilled for commercial fisheries for this area would be $43.1. Using this simplified approach, the cost-per-barrel spilled for commercial fisheries ranges from $126 for the North Atlantic to $4 for the Straits of Florida (Table II.A.2.1). The use of this loss-per-barrel-spilled coefficient, multiplied by the expected amount of oil spillage in an area, provides the basis for the later measurement of direct commercial fishery losses for each area.5/

Secondary Losses. Secondary (multiplier) effects refer to the indirect losses in income that can result from an oil spill. As noted previously, secondary effects may occur at the regional level but usually are not considered social costs; however, these effects may constitute social costs under some conditions. The commercial fishing industry appears to be particularly susceptible to secondary effects, especially in isolated areas with high unemployment rates or few alternate job possibilities. If a spill in such an area reduces the demand for fish, then the reduced derived demands for inputs to the region's fishing industry causes an indirect social cost, if resources are thereby made idle or earn less. Indirect losses also can occur in forward markets, for example, if reduced fish landings due to a spill lead to unemployed labor and capital resources at processors, canners, or wholesale and retail facilities because substitute fish products are unavailable.

Estimation of secondary effects typically involves the application of an input-output, economic base, or other regional economic model (e.g., Grigalunas and Ascari, 1982; Rogers and Mayer, 1982; and King and Flagg, 1983). The size of the multipliers estimated with such a model depend upon the level of industry aggregation, the geographic region encompassed, and the base year(s) used for the study. This report assumes that OCS-oil spill-related commercial fisheries losses in any planning area impose secondary regional and social costs. Representative results are used to characterize secondary effects from commercial fisheries losses; in each case when the available study presented

Table II.A.2.1 Value of Commercial Fishery Landings By Planning Area and Estimated Loss Per Barrel Spilled

Planning Area	Million $ (1983)a/	Ratio of Area to So. Calif.	Loss per Barrel of Oil Spilled (1987)g/
North Atlantic	528	3.5	126
Mid Atlantic	157	1.0	36
South Atlantic	140b/	.9	33
Florida Straits	19	.1	4
East Gulf of Mexico	95b/	.6	22
Central Gulf of Mexico	324	2.1	76
West Gulf of Mexico	188	1.2	43
Southern California	152	1.0	36
Central California	26	.2	6
Northern California	24	.2	6
Washington-Oregon	100	.7	26
Navarin Basin	27c/	.2	6
Beaufort Sea	*c/,d/		*d/
Chukchi Sea	*c/,d/		*d/
St. George Basin	24c/	.2	6
North Aleutian Shelf	115c/	.7	27
Gulf of Alaska	232c/	1.5	55
Shumagin	21c/	.1	5
Norton Basin	2c/	*d/	*d/
Hope Basin	2c/	*d/	*d/
Kodiak	91c/	.6	22
Cook Inlet	50c/	.3	12

Source:

a/U.S. Department of Commerce, National Marine Fisheries Service, Fishery Statistics of the United States, 1983, Washington, DC, April 1984, pp. 4-5. Reported state landings were allocated to conform to planning areas in some cases, based on landings by port.

b/Data for the east and west coasts of Florida provided by Mr. Ronald Schultze, National Marine Fisheries Service, Woods Hole, personal communication, August 21, 1984.

c/The 1983 value of landings for these areas was estimated by allocating the region-specific landings reported in State of Alaska, Alaska 1982 Catch and Production (July, 1984) to each Alaskan OCS planning area. All 1982 dollars were converted to 1983 values.

d/* = less than one million dollars.

g/Product of $35 per barrel basic loss and the area-specific factor in column two.

more than one commercial fisheries multiplier estimate, the highest number was used. The resulting estimates of secondary effects range from $89 to $273 per $100 direct loss in commercial fisheries (Table II.A.2.2) Hence, a commercial fishing industry income loss of $100 due to an oil spill will result in an additional, secondary (indirect and induced) loss in income of from $89 to $273, depending upon the geographic region concerned.

3. Tourism and Recreation Losses

Tourism Industry Losses. If an oil spill occurs and comes ashore and affects the tourist season, losses could be realized by local hotels, other guest quarters, transportation-related firms, restaurants, retail and other establishments that cater to tourists, and to residents engaged in similar recreational activities. This combination of businesses is collectively referred to as the tourist industry.

Local tourist industry losses are measured by the reduced profits -- not expenditures -- realized by owners and by the lower earnings of employees because of the spill, allowing for the influence of weather and other factors which also can affect the tourist industry. Further, the estimated loss in profits from reduced tourism should be net of any beneficial effects resulting from expenditures made by research and media personnel and curious onlookers who typically visit an area following an environmental incident.

A particular locale's tourism industry can suffer serious losses from a spill. However, from an aggregate perspective, it is likely that the losses in one location will largely be offset by gains at other, unpolluted substitute sites within the same planning area to which tourists are diverted. Evidence from the Santa Barbara spill (Head and Sorensen, 1970, pp. 194-202) supports this tourist-diversion argument.

When tourism industry gains and losses offset one another within a planning area following an oil spill, neither social costs nor regional costs are incurred. However, it is possible that the adverse publicity which can be expected when an oil spill strikes beaches in one OCS area could divert tourists to another area. For example, an estimated 245 thousand tourists who were expected to visit Brittany's beaches in the summer of 1978 instead went elsewhere following the AMOCO CADIZ spill, although poor weather may have been a contributing factor to the region's tourism industry losses (Grigalunas et al., 1983).

To allow for possible regional tourism industry

Table II.A.2.2 Secondary Income Losses (in 1987 dollars) Resulting From a $100 Loss in Commercial Fishing Income a/

Region	Loss
Atlantic	$ 94b/
Gulf of Mexico	89c/
West Coast	273d/
Alaska	121e/

a/Secondary losses measure the indirect and induced income losses for each $100 direct loss in income.

b/Grigalunas and Ascari (1982, p. 29).

c/Lampheer and Restrepo (198 , Appendix A).

d/King and Flagg (1982, p. 67).

e/Rogers and Mayer (1982, p. 98).

losses for OCS planning areas, we use the results of the AMOCO CADIZ study, which was perhaps the most comprehensive study of oil spill costs. The results of this study indicate that the Brittany region suffered net tourism industry losses and associated secondary (multiplier) losses of about 0.9 dollars per one dollar of non-market value recreation losses to the nation as a whole (Grigalunas, 1983, p. 183). This result is used in the sections which follow to approximate regional tourism industry direct and secondary losses.

Estimated regional tourism industry losses using this approach are believed to be overstated for two reasons. First, OCS-related oil spills which do come ashore may be cleaned up quickly or, in fact, may occur during the non-tourist season. Second, the non-market valued recreation loss (described below) used as the base to estimate tourism industry losses itself is a very conservative (i.e., high) estimate. It also should be noted that individuals suffering tourism industry losses caused by OCS-related oil spills are eligible for compensation for damages from the OCS facility operator or from the Oil Spill Pollution Fund, as provided for by Sec. 303 of the OSCLA. Hence, compensation for damages will considerably reduce any costs of an oil spill initially realized by the owners of tourism industry establishments within an OCS area.

Non-Market Valued Losses to Recreationists. These losses occur when individuals' enjoyment of ocean-oriented recreational experiences is reduced because a beach environment is polluted with oil, or because they incur additional costs to visit a non-polluted, substitute recreational site. Only losses in satisfaction to individual recreational participants are considered here; losses suffered by the owners and employees of tourism businesses were covered in the preceding section.

Because losses in the value of the recreational experience are not directly observable through the market, indirect estimation approaches involving the use of surveys must be used. The travel cost, willingness-to-pay (or sell) and other techniques all are potentially applicable to the estimation of non-market recreational losses from oil spills. However, these techniques rarely have been applied to estimate recreational losses from oil spills, because so few large spills have occurred and affected recreational beaches and because in the past, researchers were unable to respond quickly to those few spills which did take place and impact the shoreline.

Although a considerable number of studies have examined the non-market evaluation of recreation in

general and marine recreation in particular, only two estimates of non-market value losses to recreationists have been made following oil spills. Mead and Sorensen estimated losses to recreationists following the Santa Barbara oil spill. As noted, this OCS platform spill involved the loss of about 79 thousand barrels of oil over a two-month period, affecting some 30 miles of shoreline. Attempts were made to elicit the value of beach use by asking a sample of residents to equate the value of the beach experience to an activity with an established price (a movie). They estimated total losses to recreationists of $9.5 million, which is equivalent to $121 per barrel of oil spilled (in 1987 dollars).

The 1.6 million barrels of oil lost in the March, 1978 AMOCO CADIZ spill polluted some 240 miles of beaches in Brittany, the second most popular summer ocean vacation location in France. Losses were estimated for tourists and residents (1) who avoided the area because of the spill and (2) who came to, or remained in, the region but enjoyed themselves less or modified their activities because of the spill. The estimated total loss in recreationists' satisfaction in 1987 dollars ranged from $22.6 to $144.1 million, depending on the technique and assumptions used to evaluate losses (Brown, 1985, p. 106). These results imply non-market valued recreational losses of from $14.2 to $90.0 per barrel spilled for this incident (in 1987 dollars).

In addition to the studies cited above, two recent analyses describe the effects of oil spills on beach use. Freeman, Holland and Ditton (1985) found that predicted negative impacts of the 1979 IXTOC I spill on coastal Texas park visitation could not be substantiated. They concluded that most of the impact of the spill was due to disruption in gasoline availability (p. 23).6/ However, the authors acknowledge that they only studied visitation; possible effects of the spill on the quality of visitors' recreational experiences were not considered (p. 23). Using data from the Texas Parks and Wildlife Department, a David M. Dorbusch & Co. study reported some 108 thousand fewer visitors to Galveston Island State Park in the two month period following the August 3, 1984, ALVENUS oil spill (1985, p. 8). Unfortunately, no economic analysis was made of the costs of this spill. For this reason, it is not possible to use the information given to assess correctly the economic loss to recreationists resulting from the decrease in beach use because of the ALVENUS oil spill.

In addition to the above case studies, Wilman

(1984) has simulated the recreational losses which could result from hypothetical oil spills stemming from Georges Bank OCS oil operations coming ashore on Cape Cod. Her analysis is based on the hedonic approach, which attempts to place implicit values on particular coastal recreation attributes.

The Wilman analysis uses a number of alternative assumptions to generate a wide range of estimates of possible recreation losses. In adapting her results for this analysis we use the estimated losses for cases where 90 percent cleanup of the spill is assumed; oil spilled is assumed to degrade at 50 percent per year; and damages are assumed to increase in real terms at 7 percent annually (1984, p. 139). The recreational losses estimated by Wilman using these assumptions amount to $792 per barrel in the case of a 1,000 barrel spill to $32.8 per barrel for a 37,500 barrel spill (in 1987 dollars).7/

Mindful of the many difficult issues inherent in any attempt to assess potential non-market value recreational losses from an oil spill in a particular case, a simplified approach is adopted to provide some perspective on the possible magnitude of these losses across OCS planning areas. First, each OCS area is assigned to a category reflecting the relative threat believed to be posed to recreation in the area from OCS production and transportation. This information is presented in Table II.A.3.1. Second, each planning area is assigned a dollar figure reflecting a judgmental loss in non-market recreational values per barrel spilled and coming ashore. The precise dollar figure corresponds to the degree of threat posed to the area and ranges from $402 per barrel spilled for high risk areas to $100 per barrel for the low risk areas. The moderate-to-high risk case is the average of the per barrel loss results estimated in the Wilman study of Georges Bank; the low-to-moderate and negligible-to-low risk categories, respectively, are assumed to result in losses per barrel which are one-half and one-fourth of the moderate-to-high risk value. Given the much lower recreational loss estimates found in actual case studies of oil spills, given the much lower estimates found in the Wilman study itself (but not used in this analysis), and given the fact that spilled oil which does come ashore may do so in a non-tourist season, the per barrel estimates of recreation losses used here are believed to overstate these losses substantially.

Actual non-market valued losses depend on whether or not spilled oil comes ashore. Hence, in the calculations made later, the amount of spilled oil expected to reach land for each planning area is a key

piece of information used to assess possible non-market value recreational losses across OCS planning areas.

4. Ecological Costs

Ecological costs are among the most difficult potential costs of an oil spill to quantify in economic terms. To estimate potential ecological costs it is necessary to ascertain the extent of specific biological losses and then to assign an economic value to these losses. Since most of the organisms affected by a spill are not directly consumed or otherwise exchanged in markets or used for viewing, establishing an economic value becomes problematical and must be speculative.

Various conceptual approaches exist, in principle, for evaluating the economic cost of ecological losses following a spill (e.g., food web models, replacement cost, and willingness to pay or sell techniques). However, in practice the state of the art, and the uncertainties typically involved, are such that rarely can economically defensible estimates of ecological damages be made with confidence (Brown, 1983, pp.81-82). For these reasons, administratively- or legally-determined values, and not economically-based measures, are usually employed to set the ecological damages of oil spills.

The discussion of potential ecological costs draws on the results of two case studies, the AMOCO CADIZ oil spill, described earlier, and the 1973 ZOE COLCOTRONI spill. The assessments of ecological costs in these studies are the most frequently cited and the best documented such analyses available and hence are the most relevant sources for the present effort.

In the AMOCO CADIZ spill, an estimated sixty million marine organisms were killed (Chasse, 1979). Although it was not possible to develop estimates of ecological costs based on established economic principles, the use of unit values employed by a local biological station which sold some of the species impacted by the spill, and the adoption of a unit value used by the State of California to place a dollar value on organisms in the environment killed by oil spills, resulted in estimated ecological costs of $66.8 million and $26.4 million, respectively (Brown, 1983, p. 82). Hence the per barrel cost is $16.5 or $41.6 (in 1987 dollars), if one accepts this approach for assessing ecological costs.

In the ZOE COLCOTRONI incident, the 36 thousand barrels lost severely polluted the shoreline and some twenty acres of mangrove forest in Bahia Sucia, Puerto

Table II.A.3.1 Risk Categories and Per Barrel Loss Figures for Non-Market Valued Losses to Recreationists by OCS Planning Areas

Risk Category	OCS Area	Loss Per Barrel Spilled and Reaching Shores/
Moderate to High:	Atlantic	$413
	Gulf of Mexico	413
	Pacific	413
Low to Moderate:	Cook Inlet	201
	Gulf of Alaska	201
Negligible to Low:	Rest of Alaska	102

a/See text for a discussion of the development of the per barrel loss estimates.

Rico. Replacing the dead and damaged mangroves (replanting, monitoring, and fertilizer costs) cost an estimated $1.1 million. In addition, the use of the lowest unit price from the catalogues of firms which market biological supplies similar to those destroyed in the spill resulted in an estimate of the replacement cost of the 92.1 million marine animals lost to the environment of $10.4 million (Sorensen, 1977).8/ Thus, the total estimated cost per barrel spilled in this case amounted to $319 (in 1987 dollars), if one assents to the use of catalogue prices (vs. in situ values) to assess the economic loss of organisms in the marine environment.

Potential ecological costs are presumed to be greater than zero, but the state-of-the-art simply does not currently allow economically defensible estimates of these potential damages to be derived in most cases. Faced with the wide divergence in estimated ecological costs obtained when use is made of one or another administratively-determined rule, the present analysis adopts the results of past studies, adjusting them to reflect the relative marine productivity and environmental sensitivity of the different OCS planning areas (see Appendix I). The planning area with lowest productivity and environmental sensitivity score is assigned a unit ecological loss of $41.7 per barrel of oil spilled, while the area with this highest score are assigned a loss value of $319.7 per barrel spilled, the highest per barrel cost cited.9/ Areas of intermediate productivity and sensitivity are given intermediate sensitivity values, based on their productivity and sensitivity score.

Table II.A.4.1 summarizes the ecological loss value per barrel of spilled oil for each planning area used in subsequent calculations, based on the approach outlined above. It is noted that the low available ecological loss values of $16.4 per barrel in the AMOCO CADIZ case is not used, nor is any distinction made for spilled oil which remains at sea (and thereby generally results in lower potential ecological costs than oil affecting the coastal environment). If these considerations were to be included in Table II.A.4.1 and in subsequent calculations, the estimated potential ecological costs would be lower than with the adopted approach.

5. Subsistence Losses

Subsistence lifestyles are an important, and in some cases a predominant, way of life in a number of planning areas in Alaska. In specific cases, subsistence harvesting of marine mammals, fish, sea birds and eggs, and other marine and land animals and

Table II.A.4.1 Relative Marine Productivity and Environmental Sensitivity and Assigned Ecological Cost Per Barrel Spilled for OCS Planning Areas

Planning Area	Relative Marine Productivity and Environmental Sensitivity Scores/	Ecological Cost per Barrel Spilled b/
North Atlantic	207	$138.6
Mid-Atlantic Areas	198	127.1
South Atlantic	230	167.3
Straits of Florida	228	165.4
East Gulf of Mexico	208	139.9
Central Gulf of Mexico	254	198.6
West Gulf of Mexico	180	104.2
Southern California	213	146.3
Central California	227	164.1
Northern California	239	179.4
Washington-Oregon	256	201.1
Gulf of Alaska	235	174.3
Kodiak	264	211.3
Cook	272	221.5
Shumagin	265	212.6
No. Aleutian	327	291.6
St. Georges Basin	281	233.0
Navarin Basin	131	41.7
Norton Basin	280	231.7
Hope Basin	349	319.7
Chukchi Sea	204	134.8
Beaufort Sea	261	207.5

a/Source: U.S. Department of Interior, Secretarial Issues Document, 1986 Proposed Five-Year Lease Schedule, Appendix I, Table I.5.

b/Source: See text for a discussion of the development of per barrel ecological cost estimates. Per barrel cost values were assigned to each area using the formula: area cost/bbl = 41.7 + 1.275 (areas score - 131).

plants account for as much as 80 percent of a community's diet (Little and Robbins, 1984, p. 29). In addition, purchases made in the cash economy are often made feasible through the use of the proceeds from the sale of harvests and artisanal craft items such as ivory carvings and skin and fur garments utilizing the by-products of subsistence harvesting.

OCS oil and gas operations are viewed as imposing a risk to subsistence communities in addition to the risks of severe weather and fluctuations in the stocks of particular species traditionally faced by these communities. Marine mammals and fish could be damaged or killed, should OCS operations result in air or water pollution which affects area habitats. Noise and visual pollution and water and air pollution could cause species to leave their habitats and/or alter their migratory routes, thereby imposing costs on native communities (Little and Robbins, 1984, pp. 333-334).

According to Little and Robbins, the effects of a decline in major subsistence resources from OCS oil and gas operations or other sources on the community they studied would depend upon a variety of factors:

> If only one or a few species were affected, it might be possible for islanders to intensify hunting efforts for the unaffected species in an attempt to replace reduced or lost resources. The success of such alternative hunting strategies would be determined by the magnitude of the disruption, the number of species affected, the availability of alternative species, the season of the year, the volume of stored subsistence products, the length of the disruption and a host of other factors. Clearly, a reduction in the bird population would not pose the physical threat that the reduction in the walrus herd would. A 10 percent reduction in the seal population is less serious than a 90 percent reduction. Finally, a less than catastrophic reduction in the winter walrus herd is more significant than an equal reduction in the spring walrus herd.

In addition to harvest disruptions, other types of subsistence losses can occur. An influx of workers who pursue recreational fishing and hunting could lead to competition with members of native communities for stocks of salmon and halibut and other fishery and wildlife resources.

It is recognized that standard economic concepts may have little applicability in assessing the consequences of OCS oil and gas operations on native cultures dominated by values of kinship, sharing and

community (Jorgensen et al., 1984; Little and Robbins, 1984). Nonetheless, for those limited aspects of subsistence lifestyles where economic values may have some relevance, attempts have been made to measure the economically quantifiable losses which could be realized, should an oil spill disrupt the harvest of a subsistence community. In an earlier report (Tentative Proposed Final Secretarial Issue Document, 1982, Appendix 8, p. 14), it was estimated that an oil spill striking land could result in a loss equivalent to $20.5 per barrel of oil coming ashore. Updating this figure to 1987, it is assumed that in areas where subsistence lifestyles occur, a loss of $27 per barrel spilled results.

Other types of losses in subsistence areas, such as ecological costs, are included in other sections of this appendix. The important non-economic aspects of possible disruptions to subsistence communities caused by OCS oil and gas operations are reviewed in the EIS accompanying the proposed five-year lease schedule and are examined in sale-specific EIS's.

6. Value of the Lost Oil

The market value of the oil spilled, less the net value of oil recovered and sold, is the correct measure of this cost. For each planning area, market value is measured by the landed price of imported oil of the same quality (specific gravity and sulfur content) as the OCS oil spilled.

For purposes of this analysis, the per barrel value as of January 1, 1987 of OCS oil spilled is $28.50 in the Atlantic and the Gulf of Mexico and $26.30 for the West Coast and Alaska. Oil prices are assumed to increase one percent annually in real terms. These values correspond to the intermediate initial price assumption being used in the estimation of the economic benefits of OCS hydrocarbon development in other sections of the analysis of the proposed five-year OCS leasing schedule. No allowance is made for the value of recovered oil, which overstates this cost somewhat.

7. Other Costs

This miscellaneous category encompasses legal-administrative costs, research costs, and losses in property values which could arise as a result of OCS-related oil spills.

<u>Legal-Administrative Costs</u>. The social costs of OCS-related oil spills include the opportunity costs of the additional resources used for legal purposes as a

consequence of the spills. The costs of administrative and judicial proceedings could be measured, in principle, by the amounts paid to attorneys and experts, the value of time spent by the parties involved, and any amounts spent in excess of normal expenditures.

Determination of liability and damages is a complex and time-consuming process, and legal costs can be considerable. Legal costs of $18 per barrel spilled (in 1987 dollars) are documented for the 1976 STC-101 Chesapeake Bay oil spill (Hughes, 1982, p. 65), but little other useful information exists concerning legal costs because of the proprietary nature of these costs.

For this analysis, legal-administrative costs of $18 per barrel are assumed for all spills. Use of an estimate identical to the cost per barrel of the STC-101 spill likely results in an overstated estimate of these costs because: (1) strict liability established under the OCSLA (Sec.303) significantly reduces the legal-administrative costs of OCS-related oil spills and (2) spills remaining at sea and the vast majority of small spills can reasonably be expected to involve fewer (conceivably no) contestable claims for damages and hence are unlikely to result in legal-administrative settlement costs.

Research costs. The cost of studying the fate and effects of spilled oil, and of establishing biological, economic, and other damages, can be considerable. In the AMOCO CADIZ case, research costs (in 1987 dollars) amounted to $6.6 million or $4.11 per barrel spilled (U.S. Dept. of Commerce, 1983, p. 132-3). Research costs of about $8 (in 1987 dollars) per barrel were reported for the ARGO MERCHANT oil spill (U.S. General Accounting Office, 1977, pp. 7-9).

The analysis which follows is based on the assumption that research costs per barrel amount to $8 for large OCS spills. This value probably overstates these costs because: (1) the benefits of new basic knowledge produced by the research are not netted out, and (2) both the AMOCO CADIZ and the ARGO MERCHANT spills were subject to particularly intensive research scrutiny because of world-wide interest.

Property value loss. If the threat of oil spills causes shoreline property values to decline -- after allowing for the influence of all other determinants of property values -- the loss can be treated as a cost of proposed OCS lease sales. An analysis of this issue following the Santa Barbara oil spill suggested that property values fell by $3.6 million (in 1987 dollars) (Mead and Sorensen, 1970, p.225). However, no property

value losses were detected in the aftermath of the 1978 AMOCO CADIZ spill (Sorensen, 1983, p. 77). Using the results for Santa Barbara (in 1987 dollars), property value losses of $45.5 per barrel are assumed for spilled oil coming ashore in the lower 48 states. A nominal figure of $5.10 per barrel coming ashore is used for Alaskan OCS areas because of their lower intensity of coastal development. The coefficient used to estimate property value losses likely overstates these costs because spills generally are viewed as accidental, transitory events.

B. Estimates of Potential Non-Oil Spill Costs

1. Air Quality Losses

OCS production, processing, loading and unloading, storage and transport activities generate several types of discharges into the atmosphere. If incremental air emissions from OCS operations contribute to a deterioration in ambient air quality exceeding damage-threshold levels, economic costs will be imposed.

Measurement of air quality losses from OCS operations in principle involve the same methodological considerations and analytical steps associated with the measurement of damages from oil spills. To link OCS oil and gas activity and economic costs, one must relate the level of OCS operations to emissions, emissions to ambient air quality, air quality to physical damages, and the latter to economic costs. Spatial and seasonal factors further complicate attempts to evaluate air pollution costs.

The information used to provide a measure of possible OCS oil and gas air pollution costs draws upon the results of a 1979 CTARP study of OCS oil and gas activity off the coast of Southern California (U.S. Dept. of Commerce, NOAA, 1979). This research is particularly useful for the present analysis because (1) the study specifically deals with air pollution from OCS oil and gas operations, (2) its concern is with quantification of economic effects, (3) the geographic area studied, Southern California, faces the most severe air pollution problems among all OCS areas, and (4) the results are documented in some detail.

Using data from the proposed OCS lease sale #48 as a case study, the CTARP study estimated air quality losses of $0.036 per barrel of oil and $0.014 per thousand cubic feet of natural gas (in 1979 dollars) (NOAA, 1979, p. 201). The major potential cost of OCS oil and gas-related air quality losses was to health.

Regulations in effect since 1980 require firms to

use the best available control technology (BACT) or to employ offsets in order to avoid exceeding air quality significance levels. Hence, use of the emissions rates in the CTARP study, which was published prior to the adoption of present air quality regulations, would considerably overstate possible air quality losses from leasing resources beginning in 1986. A 1981 monitoring study of eight OCS facilities in Southern California and thirteen facilities in the Central Gulf of Mexico indicates that actual air emission rates are far less than the pre-regulation rates projected in the CTARP study (Baer, 1984, personal communication). Using the ratio of actual emissions from this monitoring work to the projected emissions from the CTARP study to adjust the CTARP economic loss estimates results in an estimate of air quality losses of $0.0195 per BBOE for Southern California and about one-half of this amount (0.0059 per BBOE) for the Central Gulf of Mexico (Winnor, 1985, personal communication). These figures are used in the subsequent analysis of potential social costs. Air quality losses for other OCS areas are expected to be negligible; a nominal figure of $0.00258 per BBOE (one-half the Central Gulf of Mexico unit cost) has been assumed.10/

These figures provide some perspective on air quality losses which could result from OCS operations. It must be recognized, however, that they may provide conservative cost estimates because future oil and gas operations will take place considerable distances from shore and effective air quality regulations can mitigate these potential losses.

2. Wetland Losses

Development of offshore oil and gas requires onshore support and transport facilities which can lead to wetlands losses. Dredging of pipeline or navigation canals can block or channelize water flows, thereby altering water circulation patterns. This can result in changes in water tables, tidal flows, and salinity levels, all of which can be detrimental to wetland habitats. Construction activity can lead to soil compaction and subsequent loss in water holding capacity of the wetland's soil. If these soils are not restored to preconstruction conditions, long-term changes in water quality, groundwater levels, and vegetation can result. OCS oil and gas-related activities have been cited as one of the contributing factors to salinity changes and loss of wetlands, most notably in Louisiana, although the available results do not indicate the share of wetland alterations attributable to OCS oil and gas operations vs. oil and gas operations in state waters and other activities (OLDS, 1984).

Wetlands are recognized as important nurseries and food production areas for many species of finfish, shellfish, and waterfowl. Wetlands work as buffers for flood waters and can reduce levels of erosion and subsequent sedimentation. Also, wetlands provide aesthetic benefits through provision of open space and may play important roles in purifying waters by removing excess nutrients and reoxygenating water. The essentially irreversible nature of damages resulting from wetland losses and the relatively increasing value of these natural environments (compared to manufactured goods) has been recognized in the economics literature (see, e.g., Shabman and Bertelson, 1979).

While it is easy to enumerate benefits provided, quantification of economic damages from wetland losses, particularly preservation value, is extremely difficult because the flows of services provided by these resources are not directly measurable through the market. Past studies have employed the "life support" measure of Gosselink et al. (1974), largely because alternative measures which capture the diversity of benefits from wetlands were unavailable. The life support approach estimates total primary energy production within the wetland of interest and multiplies this measure of energy by a unit value determined by dividing Gross National Product by the National Energy Consumption index. However, this life support measure of value has been severely criticized as having no meaningful relationship to standard measures of value (Walker, 1974; Shabman and Batie, 1978; Shabman and Bertelson, 1979). For example, Shabman and Batie show that the life support methodology implies a value for Virginia hay land of $6,960 per acre (in 1974 dollars), while the average price of farmland in Virginia was $556 per acre in 1974. Hence, even in cases where all services of land are captured by the owner, the life support methodology of Gosselink et al may vastly overstate the land values.

Despite severe empirical problems, numerous recent studies have attempted to measure the value of various services provided by wetlands. Several studies have sought to estimate the economic contribution of wetlands to particular fisheries (Batie and Wilson, 1979; Lynn et al., 1981), as well as overall economic returns to commercial fisheries in several estuary areas (Tihansky and Meade, 1976). Value of wetlands for wildlife management, flood control, and amenity benefits have been estimated (Gupta and Foster, 1975). Also, hedonic analysis has been used to isolate the effect of the amenity qualities of salt ponds on property values (Edwards and Anderson, 1984). Finally,

estimates are available for the value of a recreation fishing day (e.g., Morton, Smith, and Strand, 1983).

Attempts to estimate the possible economic damages from wetlands changes resulting from the expansion of OCS oil and gas operations in a planning area must relate the anticipated increase in exploration, development, production and transportation to (1) investment in pipelines and onshore support facilities, (2) acres of wetlands destroyed, and (3) economic damages. Analysis of this issue is further complicated because the investment in pipelines and other facilities needed to support proposed OCS operations depends on the rate of utilization of existing facilities and on a host of highly area-specific siting issues which can be substantially influenced by applicable state and federal rules and permitting requirements.

Given these considerations, the wetlands acreage losses for each area were estimated using the best judgment of experts within Department of the Interior. In areas with negligible or zero estimated resources, zero acreage loss is assumed. For other areas, acreage losses were allocated over time, assuming constant acreage damaged per year, starting from the lease date and culminating at the year of peak production. In addition, erosion is assumed to cause wetland damages to spread each year at a rate of 5% of the cumulative damages to date, again achieving total damages at the year of peak production.

The value per acre of wetlands is estimated by summing the estimated value of preservation benefits for each region using the economic information described above. The aesthetic and flood control benefits are taken from Gupta and Foster (1975). These values are $270 and $80 respectively (in 1972 dollars) per acre each year. These figures imply a capitalized value per acre of $11,557 (in 1987 dollars) at an 8% rate of interest.

Wildlife values per acre of wetland are estimated using area specific information on the range of per acre prices or assessed values made by Fish and Wildlife Service in acquiring wetlands acreage in each area. These per acre value ranges are given in Table II.B.2.1. This study employs the mid-point of the range of values for each region outside of Alaska as an estimate of wildlife values. Within Alaska, where these figures are unavailable and wildlife habitat is abundant, the lowest non zero figure of $50 per acre is used.

The value of wetlands as nurseries for recreational and commercial fisheries is calculated as

Table III.B.2.1 Wildlife Valuation Per Acre

	FISH AND WILDLIFE SERVICE RANGE	WILDLIFE VALUE PER ACRE
CGOM	50- 250	150
WESTGOM	450- 500	475
S.CALIF	300- 1000	650
S.ATLAN	50- 100	75
NAVARIN	N.A.	50
EASTGOM	0- 50	25
BEAUFRT	N.A.	50
CHUKCHI	N.A.	50
CEN.CALIF	300- 1000	650
N.CALIF	300- 1000	650
ST.GEORGE	N.A.	50
MID-ATLAN	500- 2000	1250
N.ATLAN	600- 1500	1050
ORE/WASH	300- 1000	650
N.ALEUTIAN	N.A.	50
GULFALASKA	N.A.	50
NORTON	N.A.	50
KODIAK	N.A.	50
HOPE	N.A.	50
SHUMAGIN	N.A.	50
COOK INLET	N.A.	50
STR OF FLORI	50- 50	50

follows. Availability of wetlands is assumed to be a limiting factor for all fisheries. The proportion of fisheries losses is assumed to be equal to the proportion of wetlands destroyed. Fisheries losses are then calculated by multiplying the total value of the fishery by the proportion of total available wetland which is destroyed by onshore development. For example, the proportion of wetlands lost in the Western Gulf of Mexico is calculated by dividing wetland acreage losses (408 acres, including erosion) by total esturine wetlands in the region (1.715 million acres) to calculate the proportion of wetlands which are destroyed. The total value of a commercial fishery's catch is then multiplied by this figure to determine the loss in commercial fisheries. For recreational fisheries, the total number of recreational fishing days is obtained for each area (U.S. Dept. of Commerce, National Marine Fisheries Service, 1984, p. 20).11/ This is multiplied by an estimate of the marginal value of a recreational fishing trip for striped bass from Norton, Smith and Strand (1983). Norton et al. give values ranging to a maximum of $12.63 for recreational fishing days in various areas on the Atlantic coast. For this section, the highest marginal value per day is used. Adjusted to 1987 dollars, this value is $15.45 per day fished. In the Western Gulf, the annual value of an acre of wetlands for recreational fishing is $15.03/day fished times 7.372 million days fished divided by total acres of wetlands (1.715 million) equals $66.41. At an 8% interest rate, this implies a capitalized value of $830.20 per acre. The value per acre for commercial fisheries is total value of catch in 1987 dollars ($229.9 million) divided by 1.715 million total acreage equals $134.00. At an 8% interest rate, this implies a capitalized value of $1676. Hence, the value of an acre of wetlands in the Western Gulf as a nursery ground for commercial and recreational fishing is $2506.

The total capitalized value of an acre of wetland in the Western Gulf is the sum of the aesthetic, wildlife, and flood control benefits ($12,046) plus the value as nursery grounds for commercial and recreational fisheries ($2506), which equals $14,554 per acre. Determining acreage damaged as described above, the total present value of (in 1987 dollars) of wetland losses in the Western Gulf is $2.29 million.

These measures are expected to overstate fisheries losses since many species, such as tuna and sea scallops, are not highly dependent upon wetlands. In addition, wetlands availability may not be a limiting factor even for those species which do depend upon wetlands. For example, Batie and Wilson (1979) and Lynn et al. (1981) both conclude that the loss of a small

amount of wetlands would not likely have much of an effect on particular wetlands-dependent fish populations. Finally, these figures represent gross value of recreational and commercial fishing from which costs of fishing should be deducted to calculate net values.

Using the methodology described above, acres of wetlands lost, value per acre of wetland and total economic losses were estimated for each region (Table II.B.2.2). As shown in the table, acres lost range from near zero to about 1013 acres. The value per acre ranges from about $11,616 to $56,090. The net present value of losses range across regions from near zero to about $6.00 million.

3. Commercial Fishing Area Preemption and Gear Losses

Area Preemption Losses. The emplacement of substantial numbers of OCS production facilities, pipelines and pumping stations in important commercial fishing grounds will preclude fishing in affected locations and could decrease catch per unit effort and lower fishermen's net earnings.

The owners, captains and crews of fishing vessels also will suffer losses if bottom gear is damaged by OCS oil and gas-related bottom obstructions, structures or facilities.

A number of studies in the North Sea, where similar issues are of concern, and in the United States indicate that commercial fishing area preemption and gear losses are small in total (e.g., Woods Hole Oceanographic Inst., 1976; Univ. of Rhode Island, 1977; Univ. of Aberdeen, 1978; Centaur Associates, Inc., 1984). Nonetheless, these conflicts can be contentious to the parties concerned, and an estimate of costs is included.

A 1982 estimate suggests that projected oil and natural gas production on Georges Bank could result in a peak annual loss in landings of $99.3 thousand (U.S. Dept. of Interior, 1982, p. 281). This implies a loss of $0.4 million per BBOE, based on the projected area production (U.S. Dept. of Interior, 1982, p.24). This coefficient is used for all planning areas, recognizing that it results in a high cost estimate because Georges Bank is among the most productive fishing grounds, the peak-year loss estimate is used, and the gross landed value of fish (and not net earnings) is used to evaluate losses.

Gear Losses. Recent claims against the Fishermen's Contingency Fund of the OCSLA (Title IV) for commercial

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Table II.B.2.2 Estimated Wetland Losses for Each OCS Planning Area Resulting From the Production of all Leasable Resources Unleased as of Jan 1,1987

AREA	ACRES LOST	VALUE PER ACRE	PRESENT VALUE
CGOM	1013	14153	6.74
WESTGOM	408	14553	2.57
S.CALIF	41	31344	0.77
S.ATLAN	84	12895	0.62
NAVARIN	112	11808	0.76
EASTGOM	216	12153	1.05
BEAUFRT	173	11611	1.11
CHUKCHI	0	11610	0.00
CEN.CALIF	41	20731	0.51
N.CALIF	41	56091	1.38
ST.GEORGE	112	12004	0.77
MID-ATLAN	54	14556	0.36
N.ATLAN	30	37767	0.59
ORE/WASH	0	24256	0.00
N.ALEUTIAN	0	12012	0.00
GULFALASKA	0	11884	0.00
NORTON	0	11612	0.00
KODIAK	0	11757	0.00
HOPE	0	11612	0.00
SHUMAGIN	0	11734	0.00
COOK INLET	0	11873	0.00
STR OF FLO	45	12524	0.30

fishing gear losses have been at the annual rate of $1.1 million (Cooper, personal communication, 1984). Over 90 percent of recent claims are from the Gulf of Mexico; and about 60 percent of all claims acted upon in recent years have been approved (U.S. Dept. of Commerce, 1983; Cooper, personal communication, 1984).

Assuming all claims are actually a result of OCS oil and gas activity, and using Gulf of Mexico 1982 oil and gas production of 1.12 BBOE as the base, results in estimated costs per BBOE of $1.13 million (in 1987 dollars). This conservative coefficient and the 60 percent compensation rate are used in section III.B to estimate fishing gear losses and compensation for all areas for the proposed five-year schedule.

4. Infrastructure Costs

These costs refer to the incremental public investments made to support OCS oil and gas exploration, development, production and transportation. Publicly-funded port development and airport and road construction and improvement costs are examples of infrastructure costs which could occur as a result of additional OCS oil and gas operations. The capital costs of providing additional public services (schools, sewerage and water, public safety and so forth) because of OCS hydrocarbon activities also should be included in infrastructure costs; however, operating costs for these services normally would not be considered a social cost because these essential services would be provided to the individuals concerned regardless of their geographic location or industry of employment. In addition to the foregoing, necessary public sector infrastructure planning costs also should be included. However, such costs as transportation and onshore facility planning and investment costs, including user costs, incurred by companies are not considered infrastructure costs. This is so since they are already included in the estimation of company development costs used to estimate development benefits or net economic value.

Several interrelated factors make the development of area-specific quantitative estimates of infrastructure costs a difficult undertaking. First, the additional demands for public infrastructure services within a given OCS area depend upon the amount of oil and gas resources and their location, both of which are highly uncertain until considerable drilling takes place. Second, given the estimated incremental demands for services, the needed infrastructure investment depends upon the capacity of infrastructure facilities and their projected rate of utilization. For example, if the period of additional demands for

educational services in an area because of an influx of OCS-related dependents coincided with a decline in enrollments because of a smaller school-age population of area residents, existing school buildings may be adequate to accommodate the addional demand. On the other hand, even major sewerage or water systems could be strained if OCS development occurred when these systems were operating at or near capacity.

A third factor must be recognized when attempting to assess infrastructure costs which could arise from additional OCS oil and gas operations in remote OCS areas such as the Arctic. In these OCS areas some traditional public services will not be needed (for example, educational services) because dependents will not accompany oil field personnel. Further, most, if not all, other standard public services such as water, sewerage and public safety will be provided by companies in self-contained facilities. Hence, in the Artic OCS areas, publicly supported infrastructure costs are expected to be negligible.

A number of reports provide perspectives on infrastructure costs which could result from OCS oil and gas development. For instance, using particular OCS regions as examples, the Council on Environmental Quality (CEQ) (1974) provided estimates of onshore population growth and selected public service demands as a consequence of assumed levels of OCS oil and gas resource exploitation. However, the resource assumptions used in the CEQ report have proven to be far in excess of actual resource discoveries, particularly for frontier OCS areas. Moreover, the discussion of infrastructure costs in the CEQ report is too general to be of use in the present analysis. Reports which have attempted to draw lessons from hydrocarbon development in the North Sea (e.g., Baldwin and Baldwin, 1975) provide a review of offshore and onshore experiences in this area. However, such reports are of limited value for developing detailed infrastructure assessments for the U.S. because of the many differences between the U.S. and the United Kingdom in terms of oil and gas resources, the prior history of OCS development, platform fabrication and support industries in the Gulf of Mexico and because of existing infrastructure in most U.S. OCS areas.

Although systematic data concerning possible infrastructure costs are unavailable because of the indicated difficulties inherent in estimating these costs, such costs can be expected to occur in OCS areas, particularly remote areas of Alaska and in Central and Northern California where present facilities are limited and resource estimates are more than negligible. Rather than include no estimate,

which implies a zero cost, available information is used to provide what should be regarded only as a first approximation of infrastructure costs. Further consideration of infrastructure-related cost issues will be contained in the EIS for the proposed leasing program and in sale-specific EIS's.

The Bering Sea Summary Report published by the MMS OCS Oil and Gas Information Program suggests that planning and construction costs for St. George Basin infrastructure investments could amount to some $78 million (3 million dollars for planning, 9 million dollars for port construction and 66 million dollars for airport improvements) (MMS, 1984, pp. 42-44). 12/ The estimated risked developable resources in the same document are 987 million barrels of oil equivalent (p. 10). The September 1983 Summary Report indicates projected costs of about 19 million dollars for Norton Sound (7 million dollars for planning and 12 million dollars for port construction) (1983, p. 44), with risked developable resources reported to be .414 billion barrels of oil equivalent (p. 17). The indicated resource estimates, rather than the more recent Five-Year Program resource estimate, are used because the planning and construction cost estimates were based on the prior available resource estimates.

The available information implies planning, port and airport investment costs per billion barrels of oil of 81 million dollars for St. George Basin, and 48 million dollars per BBOE for Norton Sound (in 1987 dollars). Of these costs, only the planning costs are considered additional infrastructure costs to be included in the social cost estimate developed in this appendix. The estimated potential outlays for port and airport construction and improvement can be considerable in some areas, but these items are not included as additional social costs in this appendix because oil companies are expected to pay for the cost of port and airport services in the form of user fees. As such, these costs are already included in the ordinary costs of exploration, development, production and transportation used to determine net economic value (NEV) in Appendix F. High user fees for port and airport services help explain, in part, the low NEV per BOE in remote OCS areas requiring extensive investment in these services as compared to areas where only minor infrastructure investment may be required. For example, using the base-case, initial price assumption of $26.30 per barrel, the estimated NEV per BOE in the St. George Basin is only $1.42, while the comparable estimate is $4.47 for No. California. In contrast, the NEV per BOE for So. California is $5.37 (Appendix F, Table 6.A, Net Economic Value Estimates for Leasable Resources as of January, 1987). Thus, high user fees

stemming from high onshore investment costs help explain why the NEV is lower for remote areas with a relative lack of infrastructure-type facilities than for areas where such facilities are available.

In summary, user fees are included in the costs of OCS operations. For this reason, they are not counted as social costs again in this appendix because to do so would be to count these costs twice.

Planning costs per BBOE range from about $16.9 million per BBOE for Norton Sound to $3 million for St. George Basin. As a first approximation for this social cost, the average of these two estimates is assumed to apply to all non-Artic Alaskan OCS areas outside of the two areas concerned. That is, apart from St. George Basin and Norton Sound, planning costs for all non-Arctic Alaskan OCS areas are assumed to be 10 million dollars per BBOE. Per unit costs for Central and Northern California are assumed to be 5 million dollars per BBOE--one-half of the indicated costs for the Alaskan OCS areas. Because substantial development has taken place, mature OCS areas such as the Central Gulf of Mexico and Southern California are assumed to have negligible planning costs; all other OCS areas are assigned costs equal to one-fourth those assigned to Alaska (i.e., $2.5 million per BBOE). For each OCS area, all costs are assumed to be incurred in equal annual increments in the period between the lease sale and the initiation of production.

The planning costs described above are social costs; should other publicly funded infrastructure costs for schools, water supply and sewerage, public safety and the like be incurred in an OCS area, additional social costs would be realized. An interesting issue concerns the extent to which these costs are borne by residents of the area concerned. If if planning and other costs are financed by the residents of an OCS area, then these costs also are regional costs. On the other hand, if user fees and tax revenues stemming from OCS-related operations are sufficient to cover planning and other costs, then the costs concerned do not impose a net regional cost.

Bish (1976), in his study of the fiscal effects of offshore oil and gas development on state and local government, concluded that most states could expect to receive a large favorable fiscal impact from offshore hydrocarbon development, although deficits could be realized during the first few years of exploration (p. 27). Bish's results, however, assume that OCS operations do not impose large extra expenditures. Hence, in cases such as Alaska or Northern California where large infrastructure investments may be required,

it is not clear that Bish's conclusion applies. On the other hand, Texas and Louisiana studies found that OCS oil and gas operations create net fiscal deficits. However, Bish (1976, pp. 31-32) points out that because of the assumptions used, both the Texas and Louisiana studies tend to present an unduly negative assessment of fiscal impacts.

Rather than assume either a positive net fiscal impact (implying a regional gain) or a negative net fiscal impact (a regional cost) this study assumes that OCS development is on balance neutral with respect to its fiscal impact on each OCS area. The fact that State and local governments are able to establish user fees for many services (e.g., port and airport use) and can levy property, income, sales and other taxes on OCS-related operations and their personnel lends further support to the reasonableness of the position that infrastructure costs can reasonably be regarded as neutral with respect to net fiscal effects at the regional level. The only exception to the assumption that infrastructure costs are fiscally neutral at the OCS planning area level concerns planning costs. All planning costs are assumed to be borne by the residents of affected OCS areas. This is a conservative, i.e., high-cost, assumption for this particular cost since some planning costs in fact are financed by oil companies. For example, pre-development environmental studies costs at the county level are paid by oil companies.

C. Summary of Unit Cost Estimates

For convenience, the unit cost estimates derived in the preceding sections are summarized below in Table II.C.1. These results, all stated in 1987 dollars, provide the central economic building blocks for the estimation of the costs of leasing OCS planning areas.

III. Estimation of Potential Social and Regional Costs By Planning Area

A. Basic Considerations and Assumptions

1. Oil and Gas Production and Estimated Oil Spillage by Source and Area

The estimated total amount of oil spillage in an area from OCS operations depends upon the amount of oil expected to be produced, the mode of transportation (pipeline or tanker) used, and the estimated spill rate and size by source. If a spill does occur, the chance that it will reach shore depends on (1) the location of

Table II.C.1 Summary of Unit Cost Estimates Used in Analysis of Costs of Proposed OCS Five-Year Leasing Program

Cost Category	Cost per indicated unit ($1987)a/
Oil Spill Costs	
1. Cleanup and control costs	
a. Production platform	
(i) Oil comes ashore	$225-326 per bbl ashore
(ii) Oil remains at sea	$102-149 per bbl spilled
b. Pipeline	
(i) Oil comes ashore	$222-321 per bbl ashore
(ii) Oil remains at sea	$ 62- 91 per bbl spilled
c. Tanker	
(i) Oil comes ashore	$228-331 per bbl ashore
(ii) Oil remains at sea	$ 21- 32 per bbl spilled
2. Commercial fishing	
(i) Direct losses	neg-$126 per bbl spilled
(ii) Secondary (multiplier) effects	$89-273 per $100 loss in commercial fishing income
3. Tourism industry and recreation losses	
(i) Recreation losses	$102-413 per bbl spilled reaching shore
(ii) Tourism industry losses	$.9 per dollar of recreation losses
4. Ecological costs	$41.7-319 per bbl spilledb/
5. Subsistence losses	$27 per bbl spilled for Alaskan OCS
6. Value of lost oil	$26.30-28.50 per bbl spilledb/,c/
7. Other costs	
a. Legal-administrative costs	$18 per bbl spilled
b. Research costs	$8 per bbl spilled for spills ≥ 1,000 bbls
c. Property value losses	$45.5 per bbl spilled reaching shore for "lower 48"
	$5 per bbl spilled reaching shore for Alaska

Non-Spill Costs

1. Commercial fishing	
a. Area preemption	$1.5 million per BBOE produced
b. Gear losses	$1.1 million per BBOE produced
2. Air pollution	$0.019 per BBOE--So. Calif.
	$0.0058 per BBOE--Cent. Gulf
	$0.0029 per BBOE--all other OCS areas
3. Wetlands	$11,294-54,563 per acre lost[b/]
4. Infrastructure costs	neg-$10 million per BBOE[b/]

a/See text for a discussion of the derivation of the individual unit cost estimates.

b/The indicated range reflects the range of unit cost estimates used for different OCS planning areas.

c/These are 1987 base prices which are assumed to increase by 2 percent in real terms annually.

resources and the transport system relevant to the area, which determine where a spill may occur, and (2) the prevailing currents and winds, which determine the movement of oil on the water's surface.

Table III.A.1.1 and Attachment D summarize the basic information concerning resource and spill data for large spills used in the subsequent analysis of potential costs. The information presented is based on (1) the Interior Department's estimates of the risked value of leasable, resources unleased in each OCS planning area as of January 1, 1987, (2) use of the latest spill rates, by source, for large spills (Table III.A.1.2), and (3) the Interior Department's summary results, for each area, of the chance that a large spill which occurs will strike land within thirty days.

Because the use of oil spill information assumes a central role in the analysis of potential social costs, it is important to describe in some detail the oil spill information base and how it is used in the analysis. The estimated amount of spillage from large spills (≥ 1,000 barrels) depends on both the estimated rate (number) of such spills per volume of oil produced or transported and on the estimated size of spills which may occur.

Spill rates typically are expressed as the estimated average number of spills per billion barrels of oil handled. The spill rate for platforms, pipelines and tankers is adopted from the results of Lanfear and Amstutz (1983, pp. 356-358). Their results show that on the United States OCS, only 12 platform spills occured from 1964 through 1980, and only 8 pipeline spills were experienced from 1967 through 1978.

The Lanfear and Amstutz results indicate that 1 platform and 1.6 pipeline spills greater than 1,000 barrels are estimated to occur per billion barrels of oil (Table III.A.1.2). For perspective, recent OCS oil production in Gulf of Mexico has been about 250 million barrels per year. Hence, using the Lanfear and Amstutz results, we would expect, an average, 1 platform spill and 1.6 pipeline spills, greater than 1,000 barrels every four years. This judgment assumes that historic spill rates are an adequate guide to the future.

The tanker spill rate estimated by Lanfear and Amstutz is based on their analysis of worldwide tanker accidents over the period 1974-1980. The spill rate from worldwide tanker accidents is used in the analysis in this Appendix because a comparable rate has not been estimated for vessels operating in U.S. waters.

Regarding the estimated size of individual large

Table III.A.1.1 Summary of Unleased Resources as of January 1, 1987, and Probability of Large Spills Reaching Land for Planning Areas

Planning Area	Expected Leasable Resources			Transportation Mode	Probability of Spill Reaching Land
	Oil (BBOE)	Gas (BBOE)	Total (BBOE)		
Central Gulf of Mexico	1.90	2.76	4.66	P/T	.772
Western Gulf of Mexico	1.32	3.31	4.63	P/T	.728
Southern California	0.98	0.27	1.24	P/T	.500
Central California	0.32	0.09	0.41	P/T	.444
Navarin Basin	0.59	0.13	0.72	P/T/T	.150
Beaufort Sea	0.25	0.00	0.25	P/T	.231
Chukchi Sea	0.00	0.00	0.00	P/T	.225
Northern California	0.23	0.18	0.41	P/T	.444
East Gulf of Mexico	0.22	0.20	0.42	P/T	.432
South Atlantic	0.14	0.49	0.64	P/T	.039
St. George Basin	0.06	0.10	0.16	P/T/T	.144
Mid-Atlantic	0.05	0.14	0.18	P	.106
North Atlantic	0.01	0.03	0.04	P/T	.100
North Aleutian	0.00	0.00	0.00	P/T	.342
Washington-Oregon	0.02	0.04	0.06	T	.650a/
Gulf of Alaska	0.00	0.00	0.00	P/T	.851
Norton Basin	0.00	0.00	0.00	P/T	.250
Kodiak	0.00	0.00	0.00	P/T	.545
Straits of Florida	0.00	0.01	0.01	P	NA
Hope Basin	0.00	0.00	0.00	P	NA
Shumagin	0.00	0.00	0.00	P	NA
Cook Inlet	0.00	0.00	0.00	P/T	
Rest of Alaska	-------neg.-------			NA	NA

a/Because no estimate has yet been made of the chance that an oil spill in the Washington-Oregon area would strike land, we have used the average o the indicated probabilities for the nearest two OCS areas, No. Californi and the Gulf of Alaska, as the estimate for the Washington-Oregon OCS planning area.

spills, a central problem concerns how to represent the size of the "typical" spill from platforms, pipelines and tankers. Spill statistics are dominated by a few large spills; most spills are relatively small. The following facts illustrate the importance of this point:

- A single tanker spill--the 1978 AMOCO CADIZ spill (1.5 million barrels)--constitutes about 10 percent of all oil lost in the 281 large spills included in the MMS vessel oil spill data base for 1974-1984. The five largest spills comprise over one third (37 percent) of all of the oil reported lost in vessel spills over the 11 year period.

- The 77,000 barrels reported by Lanfear and Amstutz as spilled in the 1969 Santa Barbara accident account for 35 percent of all oil spilled in the 12 large domestic platform spills since 1964.

- The 1967 West Delta 73 pipeline spill (160,638 barrels) represents fully 77 percent of all oil spilled in the 8 large United States pipeline spills since 1967.

This Appendix uses the arithmetic mean to represent the "typical" spill size for each source (Table III.A.1.2). For platforms and piplines, the mean spill size was calculated from the data presented in Lanfear and Amstutz (Tables 1 and 2, p. 356). For tankers, the arithmetic mean is from the 281 reported large vessel spills for the period 1974-1984 contained in the MMS vessel oil spill data file (Anderson, personal communication, January, 1985). The last entry in the vessel spill data file is the 1984 PUERTO RICAN spill in which 5,000 barrels were lost near San Francisco, California.

Given the small number of platform and pipline spills and the fact that the spill statistics are dominated by a relatively few very large oil spills, one could argue that use of some measure of central tendency other than the mean may be justified. Use of the median value results in a spill size of 7,522 bbls for platforms, 5,500 bbls for pipelines, and about 17,800 bbls for tankers. Use of the mode or most likely value results in still smaller estimates of the "typical" spill $\geq$ 1,000 bbls. Hence, use of the mean size for large spills is consistent with the adopted principle of using a conservative, high-cost approach when a choice must be made among possible values for a variable.

In addition to large spills, 395 small spills (<1,000 bbls) are expected to occur per billion barrels

of OCS oil production (Table III.A.1.3). Small spills from production platforms and pipelines in each area are assumed to have the same probability of reaching shore as the large platform spills indicated in Table III.A.1.1. While the number of such spills is large, the total amount estimated to be spilled is equivalent to only 3762 barrels per billion barrels of production. This is in contrast with the amount estimated to be lost in large spills per billion barrels of oil from platforms (18,378 bbls), pipelines (41,500 bbls) and tankers (74,695 bbls).

The data in Table III.A.1.3 pertain to spills from production platforms and pipelines only; rates for small spills from OCS-related tankers are not available. However, the omission of small spills from tankers has a negligible effect on the overall results because the increase in the number of small spills expected from OCS tankers will be more than offset by the decrease in small spills from imported oil that is displaced by OCS oil production.

Given the spill rates for large and small spills, given area-specific estimates of unleased oil resources and given the number and expected size of spills and the number expected to come ashore, it is now possible to estimate total oil spillage for each area. This information, summarized in Table III.A.1.4, indicates for each area the total expected spillage coming ashore and remaining at sea from the production and transportation of all the OCS oil resources unleased as of January 1, 1987. The estimated amount spilled for each area also includes oil spilled from tankers transshipping oil from <u>other</u> OCS areas.

2. Basic Assumptions Regarding Imports and Oil Transportation

Two remaining issues must be addressed before the estimates of costs can be developed. First, the OCS oil-caused reductions in imports of crude oil must be made area-specific in order to recognize the costs avoided because OCS oil production reduces the amount of import-associated tanker spills. To do this, the recent port-of-entry pattern of foreign crude oil is assumed to apply over the period of concern in this analysis (Table III.A.2.1). OCS oil production in any area is assumed to lead to reductions in imported crude oil, by area, based on the proportions indicated in Table III.A.2.1.

The world wide tanker spill rate presented in Table III.A.1.2 is assumed to apply to foreign as well as domestic tankers. All tankers are assumed to have the same expected large spill size, 57,458 bbls. For

Table III.A.2.1 Distribution of Imported Crude Oil By Area, 1977-83

Area	% of Imports a/
North Atlantic	2.9
Mid-Atlantic	31.1
South Atlantic	2.3
Straits of Florida	0.6
Eastern Gulf of Mexico	0.4
Central Gulf of Mexico	23.3
West Gulf of Mexico	26.7
Southern California	4.3
Central & Northern California	2.3
Washington-Oregon	3.1
Great Lakes	3.1
	100.0

Source: Petersen, J.L., Department of Energy, Washington, DC, personal communication, 23 August 1984.

a/Column does not add to 100 percent because of rounding.

Table III.A.1.3 Estimated Number and Size of Spills <1,000 Barrels Per Billion Barrels of Oil Produced

Spill Rate	Spill Size	Average Size (bbls)
381	1-49	4.2
14	50-999	154.4

Source: Ms. Susan Gaudry, Minerals Management Service, Gulf of Mexico Regional Office, personal communication, October 12, 1984.

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Table III.A.1.4 Estimated Total Amount Spilled and Amount Reaching Shore as a Result of Producing Unleased Resources*' From ALL Areas (Barrels)

AREA	REACHING SHORE	REMAINING AT SEA	TOTAL EXPECTED SPILLAGE
CGOM	105021	28439	133460
WESTGOM	71193	23766	94959
S.CALIF	47937	35465	83403
S.ATLAN	2556	10309	12865
NAVARIN	25972	31915	57888
EASTGOM	15655	14087	29742
BEAUFRT	6496	12137	18633
CHUKCHI	0	0	0
CEN.CALIF	13703	12253	25956
N.CALIF	9818	8985	18803
ST.GEORGE	1070	2329	3399
MID-ATLAN	1444	4228	5672
N.ATLAN	243	532	775
ORE/WASH	1065	388	1453
N.ALEUTIAN	0	0	0
GULFALASKA	0	0	0
NORTON	0	0	0
KODIAK	0	0	0
HOPE	0	0	0
SHUMAGIN	0	0	0
COOK INLET	0	0	0
STR OF FLORIDA	0	0	0

*' All Resources Unleased as of Jan. 1, 1987

foreign tankers the following geographic pattern of oil spills is assumed: 15 percent at the foreign port of origin, 15 percent in the U.S. OCS area destination (all of which is assumed to strike land), and 70 percent in transit. Of this last amount, one third is assumed to occur in domestic waters in the destination OCS area and has the same chance of reaching shore as OCS-related spills in that area.

Finally, it is necessary to account for the geographic distribution of oil spills from tankers used to transship OCS oil among planning areas. This is particularly important for Alaskan OCS oil which will be shipped considerable distances to refineries in California (and perhaps the East Coast), thereby exposing sections of other planning areas to tanker oil spills. Alaskan oil is assumed to be transported following the pattern developed for the environmental analysis supporting the Draft Proposed 5-Year Oil and Gas Leasing Program. At-sea spills are distributed among planning areas in proportion to the linear distance traveled within the planning area according to the supporting environmental analysis. All oil shipped from Alaskan areas is assumed to be transported to refineries on the West Coast.19/

B. Results

1. Introduction: An Example

Before the detailed results of cost by area are presented, it is helpful to summarize by means of an example the approach used to estimate potential social and regional costs. For this exercise, the area employed is the Western Gulf of Mexico which has leasable resources as of January 1, 1987, of 1.32 billion barrels of oil and 17.4 trillion cubic feet of natural gas, for a total of 4.63 BBOE. Seventy-five percent of the oil production is expected to be delivered to refineries by pipeline; the remaining twenty-five percent is transported by tanker. The overall probability of a spill ≥1,000 bbls reaching shore in this area is .728. The analysis begins with an estimation of expected spillage, proceeds through the estimation of total potential oil spill and non-oil spill costs and concludes with an estimate of the present value of all costs resulting from the proposed leasing and development of all of the unleased resources in the example area at time zero (January 1, 1987).

1. Determine the total estimated amount spilled, by source, as if all oil was leased on January 1, 1987. The estimated number of large spills for each source is the product of the volume in billions of barrels times

the spill rate per billion barrels (Tables III.A.1.1 and III.A.1.2). Over the life of production in this area, the estimated number of large spills is:

Platform: 1.32 billion x 1.0 = 1.32 spills
Pipeline: .99 billion x 1.6 = 1.58 spills
Tanker: .33 billion x 1.4 = .46 spills

The estimated amount spilled in large spills over the entire production period is equal to the expected number times the expected size for each source:

Platform: 1.32 x 18,378 = 24,259 bbls spilled
Pipeline: 1.58 x 25,937 = 40,980 bbls spilled
Tanker: .46 x 57,458 = 26,431 bbls spilled

The estimated amount of oil from large spills to reach shore over the life of oil production is calculated in two steps. First, the amount estimated to reach shore from platforms and pipelines is the product of the estimated amount spilled times the chance that a spill will reach shore (.728 in this case):

Platform: .728 x 24,259 = 17,661 bbls ashore
Pipeline: .728 x 40,980 = 29,833 bbls ashore

Second, we must add the amount of oil lost in large tanker spills, that is estimated to come ashore. This estimate is 20,357 barrels (= 1.2 x .33 x 57,458 x .728 plus .2 x .33 x 57,458). Thus the total amount of oil from large spills estimated to come ashore is 67,851 barrels (= 17,661 + 29,833 + 20,357).

Finally, using a similar approach for small spills, the estimated amount of spillage over the entire period is equal to the expected number of spills per billion barrels times the expected size of each spill (Table III.A.1.3) which equals 3,762 barrels spilled per billion barrels of oil produced. For the Western Gulf of Mexico, the total amount of oil lost in small spills is:

1.32 x 3,762 = 4,966 bbls

Because no oil spill trajectory modeling has been done for small spills, the chance of small spills coming ashore is assumed to be the same as the chance that large spills will strike land, .728 in this case. Thus, of the total amount of oil lost in small spills, 4,611 bbls are expected to come ashore (= 4,960 x .728) over the entire production period.

The total amount of oil estimated to be lost from spills resulting from the production and transportation

of all Western Gulf of Mexico oil resources unleased as of January 1, 1987 amounts to 96,630 barrels as summarized below. The annual estimated oil spillage is calculated by multiplying the estimated yearly oil production for the area by the expected number and size of spills (Tables III.A.1.2 and III.A.1.3). The approach used to estimate annual production for each OCS area is described in Attachment A.

Estimated amount spilled (21,000 bbls)
Over the entire production period

	Coming ashore	Remaining at sea
Production	17,661	6,598
Pipeline	29,833	11,147
Tankers	20,357	6,074
Total large spills	67,851	23,819
Plus: Small spills a/	3,611	1,349
Total large & small spills	71,462 b/	25,168 b/

a/ Distributed between "coming ashore" and "remaining at sea" in the same proportion as estimated for large platform spills for this area.

b/ These totals do not agree with data in Table III.A.1.4. due to rounding errors in Table III.A.1.4., which result from the annualization of production and spillage. See Attachment A for annualization of production.

2. Determine the present value of oil-spill costs for oil coming ashore and oil remaining at sea as if all of the area's unleased resources were leased on January 1, 1987. This calculation uses the per barrel oil spill costs described in detail in Section II, together with the estimated annual spillage outlined in the previous step, to estimate the cost for each source of the spilled oil coming ashore and remaining at sea. Detailed results of the discounted cost by category, for each source, are presented in Attachment B.

Assuming all unleased recoverable resources are leased on January 1, 1987, the present value of total oil spill costs as of this date is 18.2 million.

Platforms:	$ 5.4
Pipelines:	7.5
Tankers:	4.7
Present value of oil spill costs	17.6

3. Determine the present value of air quality losses. This cost is established by multiplying the estimated air pollution cost per unit of oil and gas production for the Western Gulf of Mexico area (see section II.B.1) times the estimated annual production for the area obtained using the procedure described in Attachment A. The present value of these costs, $3.4 million, is determined by discounting the annual estimated cost over the life of production for this area for the leasable hydrocarbon resources unleased as of January 1, 1987.

4. Determine the present value of wetland losses. This loss of $2.6 million is estimated using the approach developed in Section II.B.2 and the annual production profile generated using the procedure described in Attachment A. For this calculation, the estimated value of an acre of wetland lost is $14,553 in the Western Gulf of Mexico.

5. Determine the present value of estimated commercial fishing area preemption and gear conflicts losses. The present value of this loss is estimated to be $2.2 million. It is determined by multiplying the applicable loss coefficients per BBOE (see Table II.C.1) times the annual BBOE production for each area estimated using the procedure described in Attachment A and then discounting the annual values to get the present value.

6. Estimate the potential infrastructure cost, which covers pre-lease sale and post-lease sale planning costs, as described in section II.B.4. The present value of these costs is estimated to be $10.3 million.

7. Finally, the estimated potential social costs avoided because OCS oil replaces imported oil -- thereby resulting in fewer import-related oil spills -- must be recognized. The 1.32 million barrels produced in the Western Gulf of Mexico reduce domestic imports by an equivalent amount. Reduced imports are assumed to be distributed among OCS areas based on the recent historic crude oil import shares presented in Table III.A.2.1. Knowledge of the amount of reduced oil imports by area, tanker spill rates and the expected size of spills (III.A.1.2), and the cost of oil spills per barrel in each area permits one to estimate the potential social costs avoided from reduced imports. In this case, the social cost avoided to the nation as a whole has a present value of $6.6 million.

In summary, the present value of the <u>estimated potential social costs</u> to the nation as a whole,

assuming all Western Gulf of Mexico unleased leasable resources are leased on January 1, 1987, is:

Present value of estimated potential oil spill costs:	$17.6
Present value of estimated potential non-spill costs:	18.5
Gross estimated potential social costs:	36.1
Less:	
Present value of estimated potential social costs avoided by entire nation by reducing imported oil:	-$ 6.6
Total estimated potential social net cost:	$29.5

Now that the potential social cost has been estimated, the potential regional cost can be established. The potential regional cost is measured by reducing the <u>area's</u> gross regional cost of $42.7 million by (1) the social costs avoided because of reduced imports into this area and by (2) estimated compensation payments for OCS oil spills and commercial fishing gear losses. The relevant calculations follow with all numbers stated in present value terms.

Gross area regional costs	$42.7
Less:	
Compensation payments for:	
Oil spills	-12.1
Commercial fish. gear losses	- .9
Social costs avoided because of reduced area imports	- 3.2
Estimated potential regional cost:	$26.4

In summary, the present value of the <u>regional cost</u> for the Western Gulf of Mexico of producing all the oil and gas resources unleased as of January 1, 1987, is $26.4 million.

Following the above procedure, estimates have been made of the potential social and regional costs of the proposed five-year leasing program to each OCS planning area. These results are presented in the next section.

2. Estimated Potential Social and Regional Costs for Each OCS Planning Area

<u>Introduction</u>. Using the data, assumptions and analytical approach described in detail in the preceding sections, estimates have been made of the present discounted value of the potential social and regional costs from producing all of the leasable

recoverable hydrocarbon resources unleased as of January 1, 1987.

Only the aggregated potential oil spill and non-spill cost results for each planning area are presented in this section. A detailed listing of individual oil spill costs for each OCS area is presented in Attachment B, and a listing of potential non-spill costs for each area is given in Attachment C. Attachment D provides a summary of resource information and key results for each area.

In the following subsections the results of the estimation of potential social and regional costs are explained. The results of a sensitivity analysis of social costs by area also are described.

Estimated Potential Social Costs Results for Each OCS Area. Table III.B.2.1 presents a summary of the potential estimated social costs for each OCS area as a result of producing and transporting all of the estimated leasable oil and gas resources unleased as of January 1, 1987. Continuing our use of the Western Gulf of Mexico as an example, the results in the table should be interpreted as described below.

The value of the oil spill costs ($17.6 million) plus the non-oil spill costs ($18.5 million) for the Western Gulf of Mexico is $36.1 million in 1987 dollars. This figure represents our best judgment of the total, quantifiable social costs resulting from the production and transportation of all of the area's resources. However, the potential social cost estimate of $36.1 million does not yet include recognition of the social costs avoided because oil from the Western Gulf of Mexico will back out imports, thereby reducing foreign tanker spills. Hence, the $36.1 social cost figure at this point represents "gross" social costs.

The potential social costs avoided when Western Gulf of Mexico oil backs out imports is $6.6 million (Column 4). These social cost savings are distributed among the different OCS areas based on the geographical pattern of crude oil imports indicated in Table III.A.2.1. After the social costs avoided are subtracted from gross social costs, we arrive at net social costs of $29.5 million for the Western Gulf of Mexico (Column 5). In summary, the $29.5 million is the estimated cost of developing all of the Western Gulf of Mexico leasable oil and gas resources unleased as of January 1, 1987, to the Nation as a whole.

Estimated social costs range from $40.6 million for the Central Gulf of Mexico to less than $1 million for several Alaskan OCS areas and for the No. Atlantic,

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Table III.B.2.1

Summary of the Present Discounted Value of Estimated Potential Social Costs for Each OCS Planning Area (Millions of 1987 dollars)

AREA	(1) OIL SPILL COSTS	(2) NON SPILL COSTS	(3)=(1)+(2) GROSS SOCIAL COSTS	(4) LESS: COST AVOIDED FROM REDUCED IMPORTS**	(5)=(3)-(4) TOTAL NET DISCOUNTED SOCIAL COSTS
CGOM	34.59	16.76	51.35	10.81	40.54
WESTGOM	17.64	18.49	36.13	6.68	29.46
S.CALIF	19.50	7.57	27.08	7.31	19.77
S.ATLAN	1.83	2.86	4.69	0.57	4.11
NAVARIN	21.28	6.90	28.17	3.34	24.83
EASTGOM	4.60	2.36	6.96	1.10	5.85
BEAUFRT	5.08	1.47	6.55	1.30	5.25
CHUKCHI	0.00	0.00	0.00	0.00	0.00
CEN.CALIF	5.68	2.92	8.60	2.35	6.25
N.CALIF	4.22	3.84	8.07	1.70	6.36
ST.GEORGE	1.11	2.13	3.24	0.34	2.91
MID-ATLAN	0.82	0.95	1.77	0.26	1.51
N.ATLAN	0.13	0.69	0.81	0.04	0.78
ORE/WASH	0.44	0.21	0.65	0.11	0.54
N.ALEUTIAN	0.00	0.00	0.00	0.00	0.00
GULFALASKA	0.00	0.00	0.00	0.00	0.00
NORTON	0.00	0.00	0.00	0.00	0.00
KODIAK	0.00	0.00	0.00	0.00	0.00
HOPE	0.00	0.00	0.00	0.00	0.00
SHUMAGIN	0.00	0.00	0.00	0.00	0.00
COOK INLET	0.00	0.00	0.00	0.00	0.00
STR OF FLOR	0.00	0.32	0.32	0.00	0.32

** Estimated Potential Social costs avoided to the nation as a whole from reduced needs for imported oil, assuming reduced imports (and associated oil spills) are distributed across OCS planning areas in the same proportion as indicated in Table III.A.3.1.

Oregon-Washington and the Straits of Florida (Table III.B.2.1). Generally speaking, there is a direct association between an area's total social cost and the total leasable hydrocarbon resources estimated to be contained in the area. The OCS areas with the largest estimated unleased OCS resources, the Western Gulf of Mexico, Central Gulf of Mexico and So. California also have among the highest estimated potential total social cost, while the areas with very low estimated unleased resources, such as several of the Alaskan OCS areas and the No. Atlantic and the Oregon and Washington areas have low or negligible estimated total potential social costs.

Total hydrocarbon resources alone, however, do not determine total potential social costs. The oil-gas resource composition, the transportation mode, the estimated chance that spills which occur will reach shore, together with the characteristics of an area's marine and coastal resources and environmental productivity and sensitivity, also influence total potential social costs. For example, the Central Gulf of Mexico has resources which are virtually the same as, but potential social costs which are more than thirty percent greater than, the corresponding estimates for the Western Gulf of Mexico. One important reason for the difference in social costs estimates for the two areas is that the Central Gulf of Mexico is expected to contain considerably more oil than the Western Gulf, hence, estimated spillage is greater for the former area (Table III.A.1.4). Other reasons for the difference in the estimated total potential social costs between the two areas include the fact that the Central Gulf has more valuable commercial fisheries (Table II.A.2.1) and a higher environmental productivity and sensitivity ranking (Table II.A.4.1) and is potentially more susceptible to wetland alterations (Table II.B.2.2.) than the Western Gulf of Mexico.

Another important factor determining an area's total potential social cost is that area's need for infrastructure investment caused by OCS oil and gas development. Infrastructure costs in the form of planning costs could be relatively high for several remote Alaskan OCS areas, for Central and Northern California, and for the Western Gulf of Mexico.

The net effect of all of the myriad of factors influencing social costs can be examined by assessing the social costs per unit of production--here measured as the potential social costs per billion barrels of oil equivalent (BBOE). This information is presented for each OCS area in Table III.B.2.2.

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Table III.B.2.2

Total and per BBOE net Estimated Potential Social Costs

	TOTAL NET SOCIAL COSTS	NET COSTS PER BBOE
STR OF FLORID	0.32	53.07
NAVARIN	24.83	34.39
N.ATLAN	0.78	22.19
NORTON	0.00	21.96
BEAUFRT	5.25	21.16
N.ALEUTIAN	0.00	18.24
ST.GEORGE	2.91	18.17
S.CALIF	19.77	15.93
CEN.CALIF	6.25	15.44
N.CALIF	6.36	15.37
KODIAK	0.00	15.33
GULFALASKA	0.00	14.49
EASTGOM	5.85	14.07
CHUKCHI	0.00	13.24
CGOM	40.54	8.70
WESTGOM	29.46	6.36
S.ATLAN	4.11	6.45
MID-ATLAN	1.51	8.21
ORE/WASH	0.54	9.73
HOPE	0.00	7.64
SHUMAGIN	0.00	8.82
COOK INLET	0.00	27.61

Estimated potential social cost per BBOE range from $53.1 million for the Straits of Florida to 6.4 million for the Western Gulf of Mexico and is not directly correlated with an area's total leasable resources. The relatively high potential social cost per BBOE for the Straits of Florida ($53.1 million) is explained by a combination of possible wetland alterations and low resource estimates for this area. The use of a pipeline to transport natural gas from this area could alter some coastal wetlands. The extent of coastal wetland alteration is essentially a "fixed" cost because it depends primarily on the number of pipelines (one in this case) and is not very sensitive to changes in resource estimates. Because the resource estimate for this area is so low (.006 BBOE), the estimated social cost per BBOE is highly sensitive to fixed costs. Hence, for this reason, the potential social cost per BBOE for the Straits of Florida is quite high, even though estimated total potential social cost for the area is low.

The relatively high potential social cost per BBOE for the Navarin Basin is explained by possible infrastructure costs, the relatively high ratio of oil to gas resources (see Table III.A.1.1), and the transportation scenario for this area. Other things equal, the higher an area's ratio of oil to gas, the greater the amount of estimated oil spillage per BBOE. Oil produced in the area is assumed to be shipped first by pipeline to a collection point, carried by tanker to Balboa Bay and then transported down the West Coast by tankers. Hence oil produced in this area is subject to a higher spill risk, since the oil is handled once by pipeline and twice by tankers. For these reasons the estimated number of large spills is high relative to other OCS areas, despite the modest amount of unleased resources estimated to be leasable in this area (see Table III.A.1.1). The low potential social cost per BBOE for the Mid-Atlantic ($5.2 million) reflects the fact that the modest resources estimated for this area are all natural gas (Table III.A.1.1), so that potential oil spill costs do not arise.

As noted, the cost per BBOE is determined by a number of factors. One important factor is the estimated transportation mode for oil. Since tankers result in considerably more estimated oil spillage (74,695 barrels per BBO) than pipelines (41.499 per BBO), areas relying on tankers more than pipelines to transport oil can be expected to have higher potential social costs per BBO, other things being the same.

With respect to the composition of potential social costs, an important conclusion is that oil spill

costs exceed non-oil spill costs for most OCS areas. For the lower 48 OCS planning areas, the most important potential oil spill social costs are cleanup and control costs, tourism and recreation losses and ecological costs. For the Alaskan OCS areas, cleanup and control costs and ecological costs are the principal estimated potential oil spill costs.

For the non-oil spill costs, estimated potential wetland and air quality costs are the largest potential costs in this category for several OCS areas. Though small relative to total potential social costs, potential wetland losses and/or air quality losses could be a relatively substantial part of potential social costs for the Central and Western gulf of Mexico and Southern California OCS areas (see Attachment C). It is important to stress, however, that by regulatory authority the MMS limits air emission from OCS operations (or employs offsets) to avoid significantly affecting onshore ambient air quality. Furthermore, states through their permitting authority have considerable control over wetland use. For these reasons, non-oil spill costs may be overstated. Potential infrastructure costs (planning costs) could be relatively large for some areas, especially in remote Alaskan OCS areas and in Central and Northern California and for the Western Gulf of Mexico because of the major amount of unleased resources leasable as of January 1, 1987, for this OCS area.

The potential social cost estimates presented in Table III.B.2.1 are markedly smaller than the social cost estimates (called external costs) made in conjunction with the 1982 Secretarial Issue Document for the Tentative Proposed 5-Year OCS Leasing Schedule (Appendix 8). In brief, the major reason for the differences in social cost estimates are that the present analysis uses updated, considerably lower oil and gas resource estimates and oil spillage rates and more recent economic and other information than was available for the 1982 study. In addition, the analysis carried out in this appendix builds upon the experience gained in the 1982 exercise and considerably extends and refines the previous study of social costs. A detailed comparison of the results of the estimation of social costs made in this Appendix with the results of the social cost analysis carried out in the 1982 study can be found in Section I.H. and is not repeated here.

Estimated Potential Regional Cost Results for Each OCS Area. In Section I of this Appendix, the concept of regional costs was introduced. As was indicated, the concept of regional costs is

important when assessing the distribution between residents adjacent to each planning area of the potential costs of producing all unleased hydrocarbon resources in each area.

The concept of regional cost was introduced to indicate the estimated costs borne by residents adjacent to each OCS planning area as a result of the production of all the leasable resources unleased as of January 1, 1987. Table III.B.2.3. summarizes the estimated aggregated regional costs for each OCS area, using the unit cost assumptions developed in Section II. Extending our use of the Western Gulf of Mexico OCS area as an example, the information in Table II.B.2.3 should be interpreted as described below.

The OCSLA provides for compensation for OCS-related oil spills and commercial fishing gear damages. Also, oil production in the Western Gulf of Mexico and in other OCS areas replaces imports of crude oil into the area, thereby reducing foreign tanker spills. An accurate assessment of costs to residents of the area, therefore, should be measured net of estimated compensation payments ($13.0 million) and net of the costs avoided by backing out foreign oil to this specific OCS area ($21.8 million). The net potential regional cost for the Western Gulf of Mexico is $7.8 million in 1987 dollars. The $7.8 million figure represents our best estimate of the net costs incurred by residents of all OCS areas as a consequence of producing and transporting all of the estimated leasable resources unleased in this area as of January 1, 1987.

Social Cost Sensitivity Analysis. In previous sections of this appendix, the many uncertainties inherent in the analysis of estimated potential social costs have been described. The uncertainties include the magnitude, composition, and location of leasable oil and gas resources unleased as of January 1, 1987, the precise location and timing of oil spills and the unit costs which could be associated with oil spills and non-spill adverse effects. In recognition of the many uncertainties necessarily involved in the analysis of social costs, several sensitivity analyses were carried out. The purpose of the sensitivity analysis was to gain an appreciation of how the cost estimates for OCS planning areas presented in Section III.B.2 and I.G might change in response to changes in some of the data or assumptions used in the analysis.

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Table III.B.2.3 Estimated Potential Regional Costs by Area from Development of All Areas (Millions of 1987 Dollars)

AREA	(1) OIL SPILL COSTS IN REGION	(2) NON SPILL COSTS IN REGION	(3) COMPENSATION TO REGION	(4) IMPORT COSTS BACKED OUT OF REGION	(1)+(2)-(3)-(4) POTENTIAL NET COSTS TO THE REGION
S.CALIF	26.72	7.57	13.90	2.65	17.74
NAVARIN	17.49	6.90	8.96	0.00	15.42
CGOM	45.44	16.76	23.71	28.13	10.36
WESTGOM	24.18	18.49	13.03	21.82	7.81
N.CALIF	6.46	3.84	3.39	0.00	6.91
CEN.CALIF	8.62	2.92	4.46	0.76	6.32
EASTGOM	6.05	2.36	3.10	0.12	5.20
S.ATLAN	2.12	2.86	1.28	0.26	3.43
BEAUFRT	3.26	1.47	1.70	0.00	3.03
ST.GEORGE	0.71	2.13	0.40	0.00	2.44
ORE/WASH	2.76	0.21	1.40	0.93	0.65
N.ATLAN	0.15	0.69	0.08	0.32	0.43
STR OF FLOR	0.00	0.32	0.00	0.04	0.27
CHUKCHI	0.00	0.00	0.00	0.00	0.00
N.ALEUTIAN	0.00	0.00	0.00	0.00	0.00
GULFALASKA	0.00	0.00	0.00	0.00	0.00
NORTON	0.00	0.00	0.00	0.00	0.00
KODIAK	0.00	0.00	0.00	0.00	0.00
HOPE	0.00	0.00	0.00	0.00	0.00
SHUMAGIN	0.00	0.00	0.00	0.00	0.00
COOK INLET	0.00	0.00	0.00	0.00	0.00
MID-ATLAN	0.99	0.95	0.56	3.79	-2.42

Three basic sensitivity analyses were undertaken. The first examines how the social cost estimates presented in section III.B.2 and I.G change when individual, potential oil spill and non-spill costs are assumed to take on even higher values than the conservative (i.e., high) estimates developed in section II of this appendix. The second set of sensitivity analyses considers how the social cost estimates presented in earlier sections are modified when different vessel spill sizes are used. It is emphasized that the basis for comparison of all sensitivity analyses is the social cost results presented in sections III.B.2 and I.G.

Wetlands, ecological and commercial fishing industry losses were selected for the first set of sensitivity analyses because these costs are potentially quantitatively significant and inherently difficult to estimate. The sensitivity analysis cases considered ranged from one set of results in which each of the individual costs was allowed to be 25 percent greater than the unit cost estimates presented in Section II to an extreme case in which all of the three unit costs were assumed to be 50 percent greater than the unit costs developed in Section II. Table III.B.2.4 summarizes the potential social costs by area for the extreme sensitivity analysis case. In general, the sensitivity analysis leads to a less than 30 percent increase in total discounted net social costs. This is because (1) only a subset of all costs is assumed to increase and (2) when individual oil spill costs increase, the social cost savings from backing out imported oil also increase, thereby moderating the net increase in total potential social costs. The extreme sensitivity analysis results lead to no changes in the ranking of the ten major OCS areas in terms of their total potential social costs.

The second set of sensitivity analyses examines the consequences for social costs of changing the estimated average spill size for vessels carrying OCS and imported crude oil. As described in section III.B.1, the tanker spill size used to estimate potential social costs is the average spill size based on worldwide vessel spill incidents over 1,000 barrels for the period 1974-1984. The average spill size estimated using this approach is 57,458 barrels (Table III.A.1.2). This figure was used for both domestic tankers carrying OCS oil and foreign tankers delivering imports. The use of worldwide vessel spill statistics to characterize the average size of potential spills from vessels carrying OCS oil within and among OCS planning areas greatly overstates potential oil spillage from this source. The reason for this is that

Table III.B.2.4 **SENSITIVITY ANALYSIS: Extreme High Estimates for Commercial Fisheries, Wetlands and Ecological Costs Summary of the Present Discounted Value of Estimated Potential Social Costs for Each OCS Planning Area (Millions of 1987 dollars)**

AREA	(1) OIL SPILL COSTS	(2) NON SPILL COSTS	(3)=(1)+(2) GROSS SOCIAL COSTS	(4) LESS: COST AVOIDED FROM REDUCED IMPORTS A)	(5)=(3)-(4) TOTAL NET DISCOUNTED SOCIAL COSTS
CGOM	41.04	20.13	61.18	12.38	48.80
WESTGOM	19.85	19.78	39.63	7.64	31.99
NAVARIN	23.98	7.28	31.25	3.83	27.43
S.CALIF	23.29	7.96	31.25	8.37	22.88
N.CALIF	4.91	4.53	9.44	1.95	7.49
CEN.CALIF	6.55	3.18	9.73	2.69	7.04
EASTGOM	5.29	2.88	8.18	1.26	6.91
BEAUFRT	6.02	2.02	8.04	1.49	6.55
S.ATLAN	2.29	3.17	5.46	0.66	4.80
ST.GEORGE	1.32	2.52	3.84	0.38	3.46
MID-ATLAN	1.00	1.10	2.10	0.30	1.80
N.ATLAN	0.16	0.98	1.14	0.04	1.10
ORE/WASH	0.52	0.21	0.73	0.13	0.61
STR OF FLOR	0.00	0.47	0.47	0.00	0.47
CHUKCHI	0.00	0.00	0.00	0.00	0.00
W.ALEUTIAN	0.00	0.00	0.00	0.00	0.00
GULFALASKA	0.00	0.00	0.00	0.00	0.00
NORTON	0.00	0.00	0.00	0.00	0.00
KODIAK	0.00	0.00	0.00	0.00	0.00
HOPE	0.00	0.00	0.00	0.00	0.00
SHUMAGIN	0.00	0.00	0.00	0.00	0.00
COOK INLET	0.00	0.00	0.00	0.00	0.00

A) Estimated Potential Social costs avoided to the nation as a whole from reduced needs for imported oil, assuming reduced imports (and associated oil spills) are distributed across OCS planning areas in the same proportion as indicated in Table III.A.3.1.

worldwide vessel oil spill statistics are dominated by relatively few large spills, all of which have occurred from supertanker accidents outside of U.S. waters. Hence in this regard, the estimates presented in section III.A.1 overstate estimated potential oil spillage and, therefore, the potential social costs associated with OCS oil and gas operations.

Two vessel oil spill size sensitivity analyses are carried out to show how modifications of this factor affect the social cost results net of costs avoided as OCS oil replaces imports. In each case only the average spill size for vessels is allowed to change; the spill rate per billion barrels of oil is assumed to remain the same, and all other unit costs and assumptions are the same as developed in sections II and III.A.1 and III.A.2.

First we examine how the social cost results change for each area when we use the average vessel spill size by U.S. flag vessels in U.S. waters to characterize the potential average spill size for vessels carrying OCS oil. This is a reasonable assumption because under current law, only domestic flag vessels can be used to tranship OCS oil. For the 30 such spills recorded in the MMS data file for the period 1974-1984, the average spill size is 4,971 barrels (versus 57,450 barrels using worldwide vessel spills for the same period). Using this average vessel spill size to characterize all estimated OCS vessel spills considerably lowers estimates of potential social costs (Table III.B.2.5) for areas which rely heavily on tankers to transport OCS oil. For example, the results in section III.B.2 indicate that producing all of the leasable oil and gas resources unleased as of January 1, 1987, for the Navarin Basin could result in estimated potential social costs of $24.8 million (Table III.B.2.1); using the estimate of 4,971 for the average size OCS tanker spill results in estimated potential social costs of $8.3 million, for this planning area.

The second tanker spill size sensitivity analysis examines the change in estimated potential social costs, net of costs avoided as OCS oil reduces imports, thd tanker spill size sensitivity analysis examines the change in estimated potential social costs, net of costs avoided as OCS oil reduces imports, that occur when (1) only spills in U.S. waters by U.S. flag vessels are used to estimate the average OCS vessel spill, and (2) only spills by foreign tankers in U.S. waters are used to characterize potential oil spills from foreign tankers carrying imported oil. One could argue that this is in fact the most reasonable set of assumptions since, as noted, only domestic vessels can

Table III.B.2.5 **SENSITIVITY ANALYSIS: Low Domestic Tanker Spill Size High Foreign Tanker Spill Size Summary of the Present Discounted Value of Estimated Potential Social Costs for Each OCS Planning Area (Millions of 1987 dollars)**

AREA	(1) OIL SPILL COSTS	(2) NON SPILL COSTS	(3)=(1)+(2) GROSS SOCIAL COSTS	(4) LESS: COST AVOIDED FROM REDUCED IMPORTS*)	(5)=(3)-(4) TOTAL NET DISCOUNTED SOCIAL COSTS
CGOM	27.68	16.76	44.44	10.81	33.63
WESTGOM	13.30	18.49	31.79	6.68	25.11
S.CALIF	13.09	7.57	20.66	7.31	13.35
S.ATLAN	0.81	2.86	3.67	0.57	3.10
NAVARIN	4.76	6.90	11.66	3.34	8.32
EASTGOM	2.20	2.36	4.55	1.10	3.45
BEAUFRT	2.25	1.47	3.72	1.30	2.42
CHUKCHI	0.00	0.00	0.00	0.00	0.00
CEN.CALIF	3.11	2.92	6.03	2.35	3.69
N.CALIF	2.32	3.84	6.16	1.70	4.46
ST.GEORGE	0.42	2.13	2.56	0.34	2.22
MID-ATLAN	0.37	0.95	1.32	0.26	1.06
N.ATLAN	0.03	0.69	0.72	0.04	0.69
ORE/WASH	0.13	0.21	0.34	0.11	0.23
N.ALEUTIAN	0.00	0.00	0.00	0.00	0.00
GULFALASKA	0.00	0.00	0.00	0.00	0.00
NORTON	0.00	0.00	0.00	0.00	0.00
KODIAK	0.00	0.00	0.00	0.00	0.00
HOPE	0.00	0.00	0.00	0.00	0.00
SHUMAGIN	0.00	0.00	0.00	0.00	0.00
COOK INLET	0.00	0.00	0.00	0.00	0.00
STR OF FLOR	0.00	0.32	0.32	0.00	0.32

*) Estimated Potential Social costs avoided to the nation as a whole from reduced needs for imported oil, assuming reduced imports (and associated oil spills) are distributed across OCS planning areas in the same proportion as indicated in Table III.A.3.1.

Table III.B.2.6 SENSITIVITY ANALYSIS: Low Domestic Tanker SpillSize, Low Foreign Tanker Spill Size
Summary of the Present Discounted Value of Estimated Potential Social Costs for Each OCS Planning Area
(Millions of 1987 dollars)

AREA	(1) OIL SPILL COSTS	(2) NON SPILL COSTS	(3)=(1)+(2) GROSS SOCIAL COSTS	(4) LESS: COST AVOIDED FROM REDUCED IMPORTSA)	(5)=(3)-(4) TOTAL NET DISCOUNTED SOCIAL COSTS
CGON	27.68	16.76	44.44	3.37	41.07
WESTGON	13.30	18.49	31.79	2.08	29.70
S.CALIF	13.09	7.57	20.66	2.28	18.39
NAVARIN	4.76	6.90	11.66	1.04	10.62
N.CALIF	2.32	3.84	6.16	0.53	5.63
CEN.CALIF	3.11	2.92	6.03	0.73	5.30
EASTGON	2.20	2.36	4.55	0.34	4.21
S.ATLAN	0.81	2.86	3.67	0.18	3.49
BEAUFRT	2.25	1.47	3.72	0.41	3.32
ST.GEORGE	0.42	2.13	2.56	0.10	2.45
MID-ATLAN	0.37	0.95	1.32	0.08	1.24
N.ATLAN	0.03	0.69	0.72	0.01	0.71
STR OF FLOR	0.00	0.32	0.32	0.00	0.32
ORE/WASH	0.13	0.21	0.34	0.03	0.31
CHUKCHI	0.00	0.00	0.00	0.00	0.00
N.ALEUTIAN	0.00	0.00	0.00	0.00	0.00
GULFALASKA	0.00	0.00	0.00	0.00	0.00
NORTON	0.00	0.00	0.00	0.00	0.00
KODIAK	0.00	0.00	0.00	0.00	0.00
HOPE	0.00	0.00	0.00	0.00	0.00
SHUMAGIN	0.00	0.00	0.00	0.00	0.00
COOK INLET	0.00	0.00	0.00	0.00	0.00

A) Estimated Potential Social costs avoided to the nation as a whole from reduced needs for imported oil, assuming reduced imports (and associated oil spills) are distributed across OCS planning areas in the same proportion as indicated in Table III.A.3.1.

carry OCS oil, and virtually all imports are shipped in foreign flag vessels. Further, foreign tanker spills in U.S. waters to date on average have been small relative to worldwide statistics. Hence, restricting the use of oil spill statistics to those which have occurred in U.S. waters would appear to reflect better the mix of vessel sizes and safety and operating conditions relevant to operating tankers in domestic waters. However, it should be noted that the results described below must be used with caution because they are based on the assumption that the worldwide tanker spill rate -- the number of spills per billion barrels handled -- applies to vessels operating in U.S. waters. Since spill rates for tankers operating in U.S. waters have not been estimated, it is not clear that the assumption of equal spill rates for U.S. and worldwide tanker traffic is valid.

Using data for the period 1974-1984, the average size of the 75 foreign flag vessel spills greater than 1,000 barrels in U.S. waters in the MMS data file (which includes the PUERTO RICAN spill) is 18,090 barrels. When these numbers are used to characterize the average size of OCS vessel spills and spills from foreign tankers, estimated potential social costs, net of social costs avoided by reducing imports, are lower than those presented in section III.B and in section I.G. for OCS areas that rely on tankers to ship oil but higher for areas that use pipelines (Table III.B.2.6). Again using the Navarin Basin, the estimated potential social cost for this area is $10.6 million for the sensitivity case considered here as compared to the estimate of potential social costs of $24.8 million in sections III.B and I.G. In contrast, the estimated potential social cost for the Western Gulf of Mexico, for example, actually increases from $29.5 million (Table III.B.2.2) to $29.7 million. The reason for the higher cost for OCS areas that rely on pipelines vs. tankers to move OCS oil is that the social costs avoided when OCS oil backs out imports is smaller using the lower spill sizes for foreign tankers employed in this sensitivity analysis.

The third set of sensitivity analyses examines how the base case estimates of the potential social cost for each OCS planning area presented in Tables I.G.1, I.H.1 and III.B.2.1 change in response to lower and higher resource estimates. The base case estimates of potential social costs are based on the resource estimates made for each OCS area, assuming a starting oil price of $24 a barrel, the intermediate price considered in Appendix F. The sensitivity analyses undertaken here employ the low and high resource estimates developed in Appendix F using, respectively, a low starting price of $19 per barrel for oil and a high starting oil price of $29 a barrel.

As explained in Appendix F, the use of different starting prices for oil has important implications for the estimates of leasable resources in a number of OCS areas. For example, the estimated amount of leasable resources for Alaskan OCS areas is quite sensitive to the initial starting price considered. On the other hand, the Central and Western Gulf of Mexico OCS planning areas and the So. California area show relatively small variations in leasable resource estimates in response to changes in the starting price of oil over the range considered (see Table 8, Appendix F).

The results of the sensitivity analyses are presented in TAbles III.B.2.7 and III.B.2.8. As expected, the use of a $19 a barrel starting price for oil results in generally lower estimates of potential social costs for each OCS area (Table III.B.2.7) as compared to the social costs estimated in the base case (Table III.B.2.1). The reduction in estimated social costs is especially pronounced for those Alaskan OCS areas which have positive estimates of leasable resources at a starting price of $24 a barrel but zero estimated leasable resources at a $19 per barrel oi starting price.

Use of a $29 per barrel starting price for oil leads to higher estimates of potential social costs for virtually all OCS planing areas (Table III.B.2.8). The increase in estimated social costs vs. the base case results is notable for several of the Alaskan OCS planning areas and for the No. Atlantic OCS area for which the resource estimates are sensitive to the starting oil price assumption used to estimate leasable resources in Appendix F.

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Table II.B.2.7 SENSITIVITY ANALYSIS: Low Resource Estimates ($19 per BBL)
Summary of the Present Discounted Value of Estimated Potential Social Costs for Each OCS Planning Area
(Millions of 1987 dollars)

AREA	(1) OIL SPILL COSTS	(2) NON SPILL COSTS	(3)=(1)+(2) GROSS SOCIAL COSTS	(4) LESS: COST AVOIDED FROM REDUCED IMPORTS**	(5)=(3)-(4) TOTAL NET DISCOUNTED SOCIAL COSTS
CGON	34.15	16.64	50.78	10.32	40.46
WESTGON	17.11	18.01	35.12	6.26	28.86
S.CALIF	16.42	6.50	22.93	5.95	16.97
NAVARIN	5.11	2.27	7.38	0.80	6.58
CEN.CALIF	4.47	2.41	6.89	1.79	5.10
EASTGON	3.65	2.09	5.74	0.85	4.89
N.CALIF	2.86	3.05	5.91	1.11	4.80
S.ATLAN	1.12	2.00	3.12	0.34	2.78
MID-ATLAN	0.40	0.61	1.01	0.12	0.89
N.ATLAN	0.12	0.69	0.81	0.04	0.78
ORE/WASH	0.35	0.18	0.53	0.09	0.45
STR OF FLOR	0.00	0.32	0.32	0.00	0.32
BEAUFRT	0.00	0.00	0.00	0.00	0.00
CHUKCHI	0.00	0.00	0.00	0.00	0.00
ST.GEORGE	0.00	0.00	0.00	0.00	0.00
N.ALEUTIAN	0.00	0.00	0.00	0.00	0.00
GULFALASKA	0.00	0.00	0.00	0.00	0.00
NORTON	0.00	0.00	0.00	0.00	0.00
KODIAK	0.00	0.00	0.00	0.00	0.00
HOPE	0.00	0.00	0.00	0.00	0.00
SHUMAGIN	0.00	0.00	0.00	0.00	0.00
COOK INLET	0.00	0.00	0.00	0.00	0.00

** Estimated Potential Social costs avoided to the nation as a whole from reduced needs for imported oil, assuming reduced imports (and associated oil spills) are distributed across OCS planning areas in the same proportion as indicated in Table III.A.3.1.

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Table II.B.2.8 SENSITIVITY ANALYSIS: High Resource Estimate ($29 per BBL)
Summary of the Present Discounted Value of Estimated
Potential Social Costs for Each OCS Planning Area
(Millions of 1987 dollars)

AREA	(1) OIL SPILL COSTS	(2) NON SPILL COSTS	(3)=(1)+(2) GROSS SOCIAL COSTS	(4) LESS: COST AVOIDED FROM REDUCED IMPORTS**	(5)=(3)-(4) TOTAL NET DISCOUNTED SOCIAL COSTS
CGOM	34.58	16.76	51.35	10.82	40.52
WESTGOM	17.64	18.49	36.13	6.68	29.44
NAVARIN	23.17	7.43	30.60	3.63	26.97
S.CALIF	19.85	7.70	27.55	7.45	20.10
EASTGOM	5.19	2.53	7.72	1.25	6.48
N.CALIF	4.21	3.84	8.06	1.70	6.36
CEN.CALIF	5.66	2.92	8.58	2.34	6.24
BEAUFRT	6.29	1.56	7.85	1.61	6.24
CHUKCHI	6.55	0.53	7.08	1.80	5.28
S.ATLAN	2.09	3.18	5.27	0.66	4.61
ST.GEORGE	1.10	2.13	3.24	0.33	2.90
MID-ATLAN	0.82	0.95	1.77	0.26	1.51
N.ATLAN	0.26	0.81	1.06	0.08	0.98
ORE/WASH	0.43	0.21	0.65	0.11	0.54
GULFALASKA	0.21	0.24	0.45	0.04	0.41
STR OF FLOR	0.00	0.32	0.32	0.00	0.32
N.ALEUTIAN	0.20	0.14	0.34	0.04	0.29
NORTON	0.19	0.12	0.31	0.05	0.26
KODIAK	0.00	0.00	0.00	0.00	0.00
HOPE	0.00	0.00	0.00	0.00	0.00
SHUMAGIN	0.00	0.00	0.00	0.00	0.00
COOK INLET	0.00	0.00	0.00	0.00	0.00

** Estimated Potential Social costs avoided to the nation as a whole from reduced needs for imported oil, assuming reduced imports (and associated oil spills) are distributed across OCS planning areas in the same proportion as indicated in Table III.A.3.1.

FOOTNOTES

1/All monetary results are presented in constant dollars as of January 1, 1987, using the gross national product implicit price deflator as forecast by Data Resources, Inc. (DRI).

2/The judgment that OCS oil replaces imports on a barrel-for-barrel basis is quite reasonable. Since additional OCS production on the scale envisioned does not affect the price of oil, the same quantity of refined petroleum products will be consumed with or without the additional OCS oil production. Thus, OCS oil replaces imported oil, which provides the marginal supply to the U.S. Any conservatin induced by non price factors complements, and does not substitute for, OCS oil in reducing imports. OCS oil and domestic alternative energy sources are not substitutes since neither OCS oil nor alternative energy sources effect the price of oil. Finally, the judgment that OCS oil replaces imports on a barrel-for-barrel basis may understate the effect that OCS leasing has in reducing imports. This is because OCS natural gas to some extent will replace imported oil (or refined products like residual fuel); yet no allowance is made in this appendix for this fact.

3/The conversion rate used is 5.62 MCF = 1 barrel of oil, based on Btu equivalents.

4/A study of the 1979 IXTOC I oil spill could find no evidence of economic damages to domestic fisheries. (U.S. Dept. of Interior, 1982, p.181). These results are not used in the cost calculations for commerical fisheries made in this analysis.

5/One could provide an alternative perspective on possible commercial fishery losses from an oil spill by attempting to relate the per barrel damages reported in the text to value of catch per acre for each OCS planning area. However, this approach leads to lower estimates of per barrel losses for most OCS areas than does the approach used in the text. More sophisticated analyses (e.g., Spaulding, et al., 1982) are available; however, these results are applicable only to one area -- Georges Bank -- and only for a few species. Thus the results of a modeling approach along the lines of the work of Spaulding et al. simply are not available for all OCS areas, and such an analysis is beyond the scope of this study.

6/This finding conflicts with that of Restrepo and

Associates (1982, pp. 9-13) who concluded that Texas coastal tourism businesses lost some 12 million dollars as a result of the IXTOC I spill. However, the Freeman, Holland and Ditton analysis is viewed as more accurate because it is based on visitation data and allowed for the influence of factors other than the oil spill which may have contributed to tourism losses (gasoline availability and price), while the Restrepo et al. results were based on interviews with businesses.

7/The losses estimated by Wilman are stated in present value terms, using a 10 percent discount rate, and all spills are assumed to occur in year 8. The per barrel estimates cited in the text were estimated by first determining the compounded value of the present value sums indicated by Wilman (p. 139) and then dividing this figure by the number of barrels.

8/This element of the claim for damages was later disallowed in court proceedings on the grounds that as a practical matter, the organisms lost would not actually be replaced.

9/The $319.7 is a high or overstated cost to use in this analysis because the replacement cost used by Sorensen to value each dead organism was based on the market value, which is considerably higher than the in situ value of organisms in the marine environment (before harvesting, processing, advertising costs, etc. and a normal profit are included). Also, mangrove environments appear to be particularly productive biologically (92 million organisms killed vs. 65 million for the much larger AMOCO CADIZ oil spill).

10/It is noted that the potential threat to air quality from OCS operations varies considerably among the several pollutants associated with OCS oil and gas activities and varies considerably within a planning area.

11/The regional recreational statistics presented in this publication were disaggregated on the basis of population to conform to OCS planning areas. Alaska was assumed to have the same number of recreational fishing days per capita as the Washington-Oregon planning area.

12/Once constructed, the infrastructure facilities on St. George Island and Norton Sound are expected to serve multiple users. In fact, the St. George Island facilities are specifically intended primarily to attract commercial fishing (Minerals Management

Service, Bering Sea Summary Report, September, 1984, p. 44).

There is no precise way to allocate the total infrastructure cost among prospective total users; we have assigned one-third of the cost to OCS oil and gas because the express intent of the construction is to serve primarily the commercial fishing industry.

13/No estimate has yet been made of the probability of a spill on the Washington-Oregon OCS striking land. In the absence of this information, we have assumed that the chance of a spill striking the Washington/Oregon coast is the average of the chance for the No. California and Gulf of Alaska areas.

14/In the event of an excess supply of crude oil on the West Coast over the period of concern, some oil will be shipped via the Panama Canal to petroleum refineries on the Gulf of Mexico and East Coast. Whether or not excess supplies of oil will occur depends upon a myriad of factors: the price of oil, leasing policy, OCS and onshore discoveries and production relative to demand, and other factors (see Norgaard and Hall, 1984). In the face of these uncertainties, we have assumed that West Coast and Alaskan OCS oil is offloaded and either refined on the West Coast or shipped via a trans-state pipeline to refineries in Texas.

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ATTACHMENT A: Description of Procedure Used to Estimate Annual Oil and Natural Gas Production from Each Area.

Estimates of annual production of oil and gas were developed using area specific information from Department of Interior on

(1) total reserve estimates.

(2) years from lease sale to initial production.

(3) years from initial production to final production.

(4) years from initial production to peai production.

(5) production in the peal year as a percentage of total production.

Production in each area is presumed to increase at a percentage rate of growth from initial to peak production, and then decline from the peal year to the final yer of production at that same percentage rate. That is, production in area i during some year, t, can be expressed as:

$$P_i(t) = \left[\frac{1}{1+g_i}\right]^{|t_p - t|} P_i(t_p)$$

where $P_i(t)$ is production in area i in year t, g_i is the area specific growth rate (or decline) and t_p is the peak year of production. A search procedure is employed to determine the valuc of g_i for each area so tht total production over the productive life of the area is equal to Interior's estimate of total reserves.

1:32 PM , October 9,1985

AREA	YRS TO PROD	YRS TO PEAK	PEAK AS PRD	TOTYEARS OF PROD	OIL	GAS	BBOE
CGOM	2.00	17.00	6.00	38.00	1.90	2.76	4.66
WESTGOM	3.00	18.00	6.00	38.00	1.32	3.31	4.63
S.CALIF	6.00	7.00	11.00	30.00	0.98	0.26	1.24
S.ATLAN	9.00	5.00	9.00	27.00	0.09	0.55	0.64
NAVARIN	10.00	4.00	8.00	25.00	0.59	0.13	0.72
EASTGOM	6.00	17.00	6.00	25.00	0.22	0.20	0.42
BEAUFRT	11.00	4.00	8.00	25.00	0.25	0.00	0.25
CHUKCHI	13.00	4.00	8.00	25.00	0.00	0.00	0.00
CEN.CALIF	6.00	7.00	10.00	27.00	0.32	0.09	0.41
N.CALIF	6.00	7.00	10.00	27.00	0.23	0.18	0.41
ST.GEORGE	10.00	4.00	8.00	25.00	0.06	0.10	0.16
MID-ATLAN	9.00	4.00	9.00	27.00	0.04	0.14	0.18
N.ATLAN	11.00	6.00	7.00	27.00	0.01	0.03	0.04
ORE/WASH	6.00	7.00	9.00	25.00	0.02	0.04	0.06
N.ALEUTIAN	9.00	4.00	8.00	19.00	0.00	0.00	0.00
GULFALASKA	10.00	4.00	8.00	19.00	0.00	0.00	0.00
NORTON	6.00	4.00	10.00	20.00	0.00	0.00	0.00
KODIAK	9.00	4.00	8.00	25.00	0.00	0.00	0.00
HOPE	13.00	4.00	8.00	25.00	0.00	0.00	0.00
SHUMAGIN	9.00	4.00	8.00	25.00	0.00	0.00	0.00
COOK INLET	9.00	4.00	8.00	19.00	0.00	0.00	0.00
STR OF FLORIDA	9.00	6.00	8.00	21.00	0.00	0.01	0.01

3:36 PM , October 3,1985

ATTACHMENT B

Present discounted value of Oil spill costs by category and source from producing all of the leasable resources unleased as of Jan 1, 1987, (in millions of 1967 dollars).

CGOM

SOURCE	CLEAN & CONTROL	COMMERCIAL FISH DIRECT COSTS	COMMERCIAL FISH SECONDARY COSTS	TOUR & RECRE	ECOLOG COSTS	SUBSIST COSTS	LOST OIL	OTHER COSTS	TOTAL COSTS	COST/ BBL SPILL	COST/BBL HANDLED
PLATFORM	2.32	0.65	0.76	3.73	2.40	0.00	0.48	0.31	10.69	255.05	5.74
PIPELINE	2.27	1.34	1.16	5.55	3.55	0.0.	0.72	0.45	16.13	225.67	10.6.
TANKERS	1.55	0.60	0.52	2.74	1.62	0.0.	0.32	0.21	7.57	266.66	15.32

WESTGOM

SOURCE	CLEAN & CONTROL	COMMERCIAL FISH DIRECT COSTS	COMMERCIAL FISH SECONDARY COSTS	TOUR & RECRE	ECOLOG COSTS	SUBSIST COSTS	LOST OIL	OTHER COSTS	TOTAL COSTS	COST/ BBL SPILL	COST/BBL HANDLED
PLATFORM	1.35	0.31	0.27	2.17	0.76	0.00	0.30	0.15	5.4.	165.15	4.19
PIPELINE	1.62	0.44	0.38	3.05	1.03	0.00	0.4.	0.27	7.47	161.8.	7.52
TANKERS	1.16	0.20	0.23	2.04	0.65	0.00	0.25	0.16	4.76	155.00	14.4.

S. CALIF

SOURCE	CLEAN & CONTROL	COMMERCIAL FISH DIRECT COSTS	COMMERCIAL FISH SECONDARY COSTS	TOUR & RECRE	ECOLOG COSTS	SUBSIST COSTS	LOST OIL	OTHER COSTS	TOTAL COSTS	COST/ BBL SPILL	COST/BBL HANDLED
PLATFORM	1.30	0.25	0.76	1.63	1.15	0.00	0.30	0.21	5.67	222.32	5.61
PIPELINE	1.40	0.35	0.54	2.02	1.46	0.00	0.27	0.26	6.61	254.45	11.56
TANKERS	1.43	0.33	0.67	2.45	1.37	0.00	0.34	0.24	7.06	282.03	21.13

S. ATLAN

SOURCE	CLEAN & CONTROL	COMMERCIAL FISH DIRECT COSTS	COMMERCIAL FISH SECONDARY COSTS	TOUR & RECRE	ECOLOG COSTS	SUBSIST COSTS	LOST OIL	OTHER COSTS	TOTAL COSTS	COST/ BBL SPILL	COST/BBL HANDLED
PLATFORM	0.07	0.02	0.02	0.01	0.11	0.00	0.03	0.02	0.27	128.77	2.65
PIPELINE	0.06	0.04	0.04	0.02	0.20	0.00	0.05	0.03	0.45	117.05	4.80
TANKERS	0.19	0.07	0.06	0.29	0.36	0.00	0.05	0.06	1.11	160.41	11.58

NAVARIN

SOURCE	CLEAN & CONTROL	COMMERCIAL FISH DIRECT COSTS	COMMERCIAL FISH SECONDARY COSTS	TOUR & RECRE	ECOLOG COSTS	SUBSIST COSTS	LOST OIL	OTHER COSTS	TOTAL COSTS	COST/ BBL SPILL	COST/BBL HANDLED
PLATFORM	0.64	0.02	0.03	0.06	0.16	0.10	0.14	0.10	1.23	54.17	2.08
PIPELINE	0.66	0.04	0.05	0.10	0.25	0.16	0.20	0.16	1.57	60.36	3.33
TANKERS	6.56	0.35	0.77	4.71	3.65	0.71	0.94	0.64	18.4.	208.21	15.00

3:36 PM , October 3,1985

ATTACHMENT B (CONT)

EASTGOM

SOURCE	CLEAN & CONTROL	COMMERCIAL FISH DIRECT COSTS	COMMERCIAL FISH SECONDARY COSTS	TOUR & RECRE	ECOLOG COSTS	SUBSIST COSTS	LOST OIL	OTHER COSTS	TOTAL COSTS	COST/ BBL SPILL	COST/BBL HANDLED
PLATFORM	0.15	0.03	0.04	0.21	0.17	0.00	0.05	0.03	0.71	147.77	3.27
PIPELINE	0.30	0.05	0.04	0.40	0.32	0.0.	0.09	0.06	1.26	141.7.	5.05
TANKERS	0.55	0.05	0.06	1.01	0.58	0.00	0.17	0.11	2.63	163.67	12.23

BEAUFRT

SOURCE	CLEAN & CONTROL	COMMERCIAL FISH DIRECT COSTS	COMMERCIAL FISH SECONDARY COSTS	TOUR & RECRE	ECOLOG COSTS	SUBSIST COSTS	LOST OIL	OTHER COSTS	TOTAL COSTS	COST/ BBL SPILL	COST/BBL HANDLED
PLATFORM	0.27	0.00	0.00	0.02	0.30	0.00	0.11	0.09	0.73	133.32	2.35
PIPELINE	0.36	0.01	0.01	0.06	0.56	0.00	0.21	0.07	2.02	121.84	5.10
TANKERS	0.87	0.1.	0.15	0.66	0.72	0.00	0.15	0.12	3.05	166.9.	12.47

CHUKCHI

SOURCE	CLEAN & CONTROL	COMMERCIAL FISH DIRECT COSTS	COMMERCIAL FISH SECONDARY COSTS	TOUR & RECRE	ECOLOG COSTS	SUBSIST COSTS	LOST OIL	OTHER COSTS	TOTAL COSTS	COST/ BBL SPILL	COST/BBL HANDLED
PLATFORM	0.00	0.0.	0.0.	0.00	0.00	0.0.	0.0.	0.00	0.00	0.00	0.0.
PIPELINE	0.00	0.0.	0.0.	0.00	0.00	0.0.	0.0.	0.0.	0.0.	0.0.	0.0.
TANKERS	0.00	0.0.	0.0.	0.00	0.00	0.0.	0.0.	0.00	0.00	0.00	0.00

CEN. CALIF

SOURCE	CLEAN & CONTROL	COMMERCIAL FISH DIRECT COSTS	COMMERCIAL FISH SECONDARY COSTS	TOUR & RECRE	ECOLOG COSTS	SUBSIST COSTS	LOST OIL	OTHER COSTS	TOTAL COSTS	COST/ BBL SPILL	COST/BBL HANDLED
PLATFORM	0.42	0.01	0.04	0.46	0.45	0.00	0.09	0.07	1.21	214.57	4.76
PIPELINE	0.32	0.01	0.04	0.44	0.40	0.00	0.03	0.06	1.35	206.33	6.56
TANKERS	0.64	0.02	0.06	1.05	0.72	0.00	0.16	0.11	2.81	237.43	17.73

N. CALIF

SOURCE	CLEAN & CONTROL	COMMERCIAL FISH DIRECT COSTS	COMMERCIAL FISH SECONDARY COSTS	TOUR & RECRE	ECOLOG COSTS	SUBSIST COSTS	LOST OIL	OTHER COSTS	TOTAL COSTS	COST/ BBL SPILL	COST/BBL HANDLED
PLATFORM	0.29	0.01	0.03	0.34	0.34	0.00	0.07	0.05	1.12	220.67	4.89
PIPELINE	0.23	0.01	0.03	0.32	0.32	0.00	0.06	0.05	1.01	212.09	6.60
TANKERS	0.46	0.02	0.05	0.75	0.57	0.00	0.12	0.08	2.05	243.13	16.16

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ATTACHMENT B (CONT)

ST. GEORGE

SOURCE	CLEAN & CONTROL	COMMERCIAL FISH DIRECT COSTS	COMMERCIAL FISH SECONDARY COSTS	TOUR & RECRE	ECOLOG COSTS	SUBSIST COSTS	LOST OIL	OTHER COSTS	TOTAL COSTS	COST/ BBL SPILL	COST/BBL HANDLED
PLATFORM	0.06	0.00	0.00	0.01	0.09	0.01	0.01	0.01	0.19	148.76	3.25
PIPELINE	0.04	0.00	0.00	0.01	0.08	0.01	0.01	0.01	0.17	134.82	5.80
TANKERS	0.21	0.02	0.04	0.21	0.20	0.00	0.05	0.03	0.75	169.95	12.69

MID-ATLAN

SOURCE	CLEAN & CONTROL	COMMERCIAL FISH DIRECT COSTS	COMMERCIAL FISH SECONDARY COSTS	TOUR & RECRE	ECOLOG COSTS	SUBSIST COSTS	LOST OIL	OTHER COSTS	TOTAL COSTS	COST/ BBL SPILL	COST/BBL HANDLED
PLATFORM	0.03	0.01	0.01	0.01	0.04	0.00	0.01	0.01	0.12	131.90	2.52
PIPELINE	0.04	0.02	0.02	0.02	0.07	0.00	0.02	0.01	0.21	120.70	5.01
TANKERS	0.10	0.03	0.03	0.15	0.12	0.00	0.09	0.02	0.50	162.14	12.11

N. ATLAN

SOURCE	CLEAN & CONTROL	COMMERCIAL FISH DIRECT COSTS	COMMERCIAL FISH SECONDARY COSTS	TOUR & RECRE	ECOLOG COSTS	SUBSIST COSTS	LOST OIL	OTHER COSTS	TOTAL COSTS	COST/ BBL SPILL	COST/BBL HANDLED
PLATFORM	0.00	0.01	0.00	0.00	0.01	0.00	0.00	0.00	0.03	143.67	3.18
PIPELINE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TANKERS	0.01	0.02	0.02	0.02	0.02	0.00	0.01	0.00	0.10	166.84	12.46

ORE/WASH

SOURCE	CLEAN & CONTROL	COMMERCIAL FISH DIRECT COSTS	COMMERCIAL FISH SECONDARY COSTS	TOUR & RECRE	ECOLOG COSTS	SUBSIST COSTS	LOST OIL	OTHER COSTS	TOTAL COSTS	COST/ BBL SPILL	COST/BBL HANDLED
PLATFORM	0.02	0.00	0.01	0.03	0.02	0.00	0.00	0.00	0.10	291.45	6.45
PIPELINE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TANKERS	0.07	0.01	0.03	0.13	0.08	0.00	0.01	0.01	0.34	305.86	22.85

N. ALEUTIAN

SOURCE	CLEAN & CONTROL	COMMERCIAL FISH DIRECT COSTS	COMMERCIAL FISH SECONDARY COSTS	TOUR & RECRE	ECOLOG COSTS	SUBSIST COSTS	LOST OIL	OTHER COSTS	TOTAL COSTS	COST/ BBL SPILL	COST/BBL HANDLED
PLATFORM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PIPELINE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TANKERS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

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ATTACHMENT B (CONT)

GULFALASKA

SOURCE	CLEAN & CONTROL	COMMERCIAL FISH DIRECT COSTS	COMMERCIAL FISH SECONDARY COSTS	TOUR & RECRE	ECOLOG COSTS	SUBSIST COSTS	LOST OIL	OTHER COSTS	TOTAL COSTS	COST/ BBL SPILL	COST/BBL HANDLED
PLATFORM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PIPELINE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TANKERS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

NORTON

SOURCE	CLEAN & CONTROL	COMMERCIAL FISH DIRECT COSTS	COMMERCIAL FISH SECONDARY COSTS	TOUR & RECRE	ECOLOG COSTS	SUBSIST COSTS	LOST OIL	OTHER COSTS	TOTAL COSTS	COST/ BBL SPILL	COST/BBL HANDLED
PLATFORM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PIPELINE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TANKERS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

KODIAK

SOURCE	CLEAN & CONTROL	COMMERCIAL FISH DIRECT COSTS	COMMERCIAL FISH SECONDARY COSTS	TOUR & RECRE	ECOLOG COSTS	SUBSIST COSTS	LOST OIL	OTHER COSTS	TOTAL COSTS	COST/ BBL SPILL	COST/BBL HANDLED
PLATFORM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PIPELINE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TANKERS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

HOPE

SOURCE	CLEAN & CONTROL	COMMERCIAL FISH DIRECT COSTS	COMMERCIAL FISH SECONDARY COSTS	TOUR & RECRE	ECOLOG COSTS	SUBSIST COSTS	LOST OIL	OTHER COSTS	TOTAL COSTS	COST/ BBL SPILL	COST/BBL HANDLED
PLATFORM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PIPELINE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TANKERS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

SHUMAGIN

SOURCE	CLEAN & CONTROL	COMMERCIAL FISH DIRECT COSTS	COMMERCIAL FISH SECONDARY COSTS	TOUR & RECRE	ECOLOG COSTS	SUBSIST COSTS	LOST OIL	OTHER COSTS	TOTAL COSTS	COST/ BBL SPILL	COST/BBL HANDLED
PLATFORM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PIPELINE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TANKERS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

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ATTACHMENT B (CONT)

COOK INLET

SOURCE	CLEAN & CONTROL	COMMERCIAL FISH DIRECT COSTS	COMMERCIAL FISH SECONDARY COSTS	TOUR & RECREA	ECOLOG COSTS	SUBSIST COSTS	LOST OIL	OTHER COSTS	TOTAL COSTS	COST/ BBL SPILL	COST/BBL HANDLED
PLATFORM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PIPELINE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TANKERS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

STR OF FLORID

SOURCE	CLEAN & CONTROL	COMMERCIAL FISH DIRECT COSTS	COMMERCIAL FISH SECONDARY COSTS	TOUR & RECREA	ECOLOG COSTS	SUBSIST COSTS	LOST OIL	OTHER COSTS	TOTAL COSTS	COST/ BBL SPILL	COST/BBL HANDLED
PLATFORM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PIPELINE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TANKERS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

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Attachment C
Present Discounted Value of Non-Spill Costs from Producing
All of the Leasable Resources Unleased as of Jan 1, 1987
(in Millions of 1987 dollars).

AREA	AIR POLLUTION COSTS	WETLANDS COSTS	COMM. FISH AREA PREM.& GEAR LOSS	INFRA-STRUCTURE COSTS	TOTAL NON-SPILL COSTS	NON-SPILL COSTS PER BBOE
CGOM	7.76	6.74	2.26	0.00	16.76	3.59
WESTGOM	3.42	2.57	2.16	10.33	18.49	3.99
S.CALIF	5.57	0.77	1.24	0.00	7.57	6.10
S.ATLAN	0.57	0.62	0.51	1.15	2.86	4.47
NAVARIN	0.60	0.76	0.50	5.03	6.90	9.54
EASTGOM	0.31	1.05	0.17	0.83	2.36	5.66
BEAUFRT	0.19	1.11	0.17	0.00	1.47	5.90
CHUKCHI	0.00	0.00	0.00	0.00	0.00	0.00
CEN.CALI	0.44	0.51	0.35	1.62	2.92	7.20
N.CALIF	0.45	1.38	0.36	1.66	3.84	9.26
ST.GEORG	0.13	0.77	0.11	1.12	2.13	13.26
MID-ATLA	0.17	0.30	0.15	0.33	0.95	5.13
N.ATLAN	0.02	0.59	0.02	0.06	0.69	19.16
ORE/WASH	0.06	0.00	0.04	0.11	0.21	3.77
N.ALEUTI	0.00	0.00	0.00	0.00	0.00	0.00
GULFALAS	0.00	0.00	0.00	0.00	0.00	0.00
NORTON	0.00	0.00	0.00	0.00	0.00	0.00
KODIAK	0.00	0.00	0.00	0.00	0.00	0.00
HOPE	0.00	0.00	0.00	0.00	0.00	0.00
SHUMAGIN	0.00	0.00	0.00	0.00	0.00	0.00
COOK INL	0.00	0.00	0.00	0.00	0.00	0.00
STR OF F	0.00	0.30	0.00	0.01	0.32	45.49

ATTACHMENT D : Summary of Information by Area

CGOM

Resources (BBOE)

Oil - 1.90

Gas - 2.76

Total - 4.66

Oil Spills

	Number of Large Spills	Amount Spilled (Large and Small)
Coming Ashore -	3.76	105021.00
Remaining at Sea -	1.07	28438.57
Total -	4.82	133459.60

TOTAL OIL SPILL COSTS -	$	34.59
NON-SPILL COSTS -	$	16.76
- OIL SPILLS BACKED OUT -	$	10.71
Total Net Social Cost -	$	40.64 Million
Net Social Cost per BBOE -	$	8.72 Million
Total Net Cost Incurred by Area Residents From Production in THAT Area	$	31.30 Million
Total Net Cost Borne by Area Residents From Production in ALL Areas	$	10.56 Million

WESTGOM

Resources (BBOE)

Oil - 1.32

Gas - 3.31

Total - 4.63

Oil Spills

	Number of Large Spills	Amount Spilled (Large and Small)
Coming Ashore -	2.46	71193.15
Remaining at Sea -	0.87	23765.88
Total -	3.33	94959.02

TOTAL OIL SPILL COSTS -	$	17.64
NON-SPILL COSTS -	$	18.49
- OIL SPILLS BACKED OUT -	$	6.61
Total Net Social Cost -	$	29.52 Million
Net Social Cost per BBOE -	$	6.38 Million
Total Net Cost Incurred by Area Residents From Production in THAT Area	$	26.43 Million
Total Net Cost Borne by Area Residents From Production in ALL Areas	$	7.97 Million

S. CALIF

Resources (BBOE)

Oil - 0.98

Gas - 0.26

Total - 1.24

Oil Spills

	Number of Large Spills	Amount Spilled (Large and Small)
Coming Ashore -	1.42	47937.12
Remaining at Sea -	1.20	35465.49
Total -	2.62	83402.61

TOTAL OIL SPILL COSTS -	$	19.50	
NON-SPILL COSTS -	$	7.57	
- OIL SPILLS BACKED OUT -	$	7.24	
Total Net Social Cost -	$	19.84	Million
Net Social Cost per BBOE -	$	15.99	Million
Total Net Cost Incurred by Area Residents From Production in THAT Area	$	19.09	Million
Total Net Cost Borne by Area Residents From Production in ALL Areas	$	18.62	Million

S. ATLAN

Resources (BBOE)

Oil - 0.09

Gas - 0.55

Total - 0.64

Oil Spills

	Number of Large Spills	Amount Spilled (Large and Small)
Coming Ashore -	0.05	2555.82
Remaining at Sea -	0.31	10309.35
Total -	0.36	12865.17

TOTAL OIL SPILL COSTS -	$	1.83	
NON-SPILL COSTS -	$	2.86	
- OIL SPILLS BACKED OUT -	$	0.57	
Total Net Social Cost -	$	4.12	Million
Net Social Cost per BBOE -	$	6.46	Million
Total Net Cost Incurred by Area Residents From Production in THAT Area	$	3.69	Million
Total Net Cost Borne by Area Residents From Production in ALL Areas	$	3.43	Million

NAVARIN

Resources (BBOE)

Oil - 0.59
Gas - 0.13
Total - 0.72

Oil Spills

	Number of Large Spills	Amount Spilled (Large and Small)
Coming Ashore -	0.58	25972.25
Remaining at Sea -	1.30	31915.36
Total -	1.89	57887.61

TOTAL OIL SPILL COSTS -	$	21.28
NON-SPILL COSTS -	$	6.90
- OIL SPILLS BACKED OUT -	$	3.31
Total Net Social Cost -	$	24.86 Million
Net Social Cost per BBOE -	$	34.44 Million
Total Net Cost Incurred by Area Residents From Production in THAT Area	$	15.42 Million
Total Net Cost Borne by Area Residents From Production in ALL Areas	$	15.42 Million

EASTGOM

Resources (BBOE)

Oil - 0.22
Gas - 0.20
Total - 0.42

Oil Spills

	Number of Large Spills	Amount Spilled (Large and Small)
Coming Ashore -	0.41	15655.28
Remaining at Sea -	0.43	14086.79
Total -	0.84	29742.07

TOTAL OIL SPILL COSTS -	$	4.60
NON-SPILL COSTS -	$	2.36
- OIL SPILLS BACKED OUT -	$	1.09
Total Net Social Cost -	$	5.86 Million
Net Social Cost per BBOE -	$	14.09 Million
Total Net Cost Incurred by Area Residents From Production in THAT Area	$	5.31 Million
Total Net Cost Borne by Area Residents From Production in ALL Areas	$	5.20 Million

READER'S CHOICE

BEAUFRT

Resources (BBOE)

Oil - 0.25

Gas - 0.00

Total - 0.25

Oil Spills

	Number of Large Spills	Amount Spilled (Large and Small)
Coming Ashore -	0.20	6495.71
Remaining at Sea -	0.50	12136.87
Total -	0.69	18632.59

TOTAL OIL SPILL COSTS -	$	5.08
NON-SPILL COSTS -	$	1.47
- OIL SPILLS BACKED OUT -	$	1.29
Total Net Social Cost -	$	5.26 Million
Net Social Cost per BBOE -	$	21.21 Million
Total Net Cost Incurred by Area Residents From Production in THAT Area	$	3.03 Million
Total Net Cost Borne by Area Residents From Production in ALL Areas	$	3.03 Million

CHUKCHI

Resources (BBOE)

Oil - 0.00

Gas - 0.00

Total - 0.00

Oil Spills

	Number of Large Spills	Amount Spilled (Large and Small)
Coming Ashore -	0.00	0.00
Remaining at Sea -	0.00	0.00
Total -	0.00	0.00

TOTAL OIL SPILL COSTS -	$	0.00
NON-SPILL COSTS -	$	0.00
- OIL SPILLS BACKED OUT -	$	0.00
Total Net Social Cost -	$	0.00 Million
Net Social Cost per BBOE -	$	0.00 Million
Total Net Cost Incurred by Area Residents From Production in THAT Area	$	0.00 Million
Total Net Cost Borne by Area Residents From Production in ALL Areas	$	0.00 Million

CEN. CALIF

Resources (BBOE)

Oil - 0.32

Gas - 0.09

Total - 0.41

Oil Spills

	Number of Large Spills	Amount Spilled (Large and Small)
Coming Ashore -	0.48	13703.14
Remaining at Sea -	0.44	12292.87
Total -	0.92	25996.01

TOTAL OIL SPILL COSTS -	$	5.68
NON-SPILL COSTS -	$	2.92
- OIL SPILLS BACKED OUT -	$	2.32
Total Net Social Cost -	$	6.28 Million
Net Social Cost per BBOE -	$	15.50 Million
Total Net Cost Incurred by Area Residents From Production in THAT Area	$	6.47 Million
Total Net Cost Borne by Area Residents From Production in ALL Areas	$	6.90 Million

N. CALIF

Resources (BBOE)

Oil - 0.23

Gas - 0.18

Total - 0.41

Oil Spills

	Number of Large Spills	Amount Spilled (Large and Small)
Coming Ashore -	0.31	9818.23
Remaining at Sea -	0.34	8985.12
Total -	0.65	18803.35

TOTAL OIL SPILL COSTS -	$	4.22
NON-SPILL COSTS -	$	3.84
- OIL SPILLS BACKED OUT -	$	1.69
Total Net Social Cost -	$	6.38 Million
Net Social Cost per BBOE -	$	15.41 Million
Total Net Cost Incurred by Area Residents From Production in THAT Area	$	6.44 Million
Total Net Cost Borne by Area Residents From Production in ALL Areas	$	7.38 Million

ST. GEORGE

Resources (BBOE)

Oil - 0.06

Gas - 0.10

Total - 0.16

Oil Spills

	Number of Large Spills	Amount Spilled (Large and Small)
Coming Ashore -	0.03	1069.79
Remaining at Sea -	0.09	2328.93
Total -	0.12	3398.72

TOTAL OIL SPILL COSTS -	$	1.11
NON-SPILL COSTS -	$	2.13
- OIL SPILLS BACKED OUT -	$	0.33
Total Net Social Cost -	$	2.91 Million
Net Social Cost per BBOE -	$	18.19 Million
Total Net Cost Incurred by Area Residents From Production in THAT Area	$	2.44 Million
Total Net Cost Borne by Area Residents From Production in ALL Areas	$	2.44 Million

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MID-ATLAN

Resources (BBOE)

Oil - 0.04

Gas - 0.14

Total - 0.18

Oil Spills

	Number of Large Spills	Amount Spilled (Large and Small)
Coming Ashore -	0.03	1443.63
Remaining at Sea -	0.13	4228.11
Total -	0.16	5671.74

TOTAL OIL SPILL COSTS -	$	0.82
NON-SPILL COSTS -	$	0.95
- OIL SPILLS BACKED OUT -	$	0.26
Total Net Social Cost -	$	1.51 Million
Net Social Cost per BBOE -	$	8.21 Million
Total Net Cost Incurred by Area Residents From Production in THAT Area	$	1.35 Million
Total Net Cost Borne by Area Residents From Production in ALL Areas	$	-2.42 Million

N. ATLAN

Resources (BBOE)

Oil - 0.01

Gas - 0.03

Total - 0.04

Oil Spills

	Number of Large Spills	Amount Spilled (Large and Small)
Coming Ashore -	0.00	242.95
Remaining at Sea -	0.01	531.73
Total -	0.02	774.68

TOTAL OIL SPILL COSTS -	$	0.13
NON-SPILL COSTS -	$	0.69
- OIL SPILLS BACKED OUT -	$	0.04
Total Net Social Cost -	$	0.78 Million
Net Social Cost per BBOE -	$	22.20 Million
Total Net Cost Incurred by Area Residents From Production in THAT Area	$	0.75 Million
Total Net Cost Borne by Area Residents From Production in ALL Areas	$	0.43 Million

ORE/WASH

Resources (BBOE)

Oil - 0.02

Gas - 0.04

Total - 0.06

Oil Spills

	Number of Large Spills	Amount Spilled (Large and Small)
Coming Ashore -	0.14	1064.80
Remaining at Sea -	0.06	387.72
Total -	0.20	1452.53

TOTAL OIL SPILL COSTS -	$	0.44
NON-SPILL COSTS -	$	0.21
- OIL SPILLS BACKED OUT -	$	0.11
Total Net Social Cost -	$	0.55 Million
Net Social Cost per BBOE -	$	9.74 Million
Total Net Cost Incurred by Area Residents From Production in THAT Area	$	0.48 Million
Total Net Cost Borne by Area Residents From Production in ALL Areas	$	1.75 Million

N. ALEUTIAN

Resources (BBOE)

Oil - 0.00

Gas - 0.00

Total - 0.00

Oil Spills

	Number of Large Spills	Amount Spilled (Large and Small)
Coming Ashore -	0.00	0.00
Remaining at Sea -	0.00	0.00
Total -	0.00	0.00

TOTAL OIL SPILL COSTS -	$	0.00	
NON-SPILL COSTS -	$	0.00	
- OIL SPILLS BACKED OUT -	$	0.00	
Total Net Social Cost -	$	0.00	Million
Net Social Cost per BBOE -	$	0.00	Million
Total Net Cost Incurred by Area Residents From Production in THAT Area	$	0.00	Million
Total Net Cost Borne by Area Residents From Production in ALL Areas	$	0.00	Million

GULFALASKA

Resources (BBOE)

Oil - 0.00

Gas - 0.00

Total - 0.00

Oil Spills

	Number of Large Spills	Amount Spilled (Large and Small)
Coming Ashore -	0.00	0.00
Remaining at Sea -	0.00	0.00
Total -	0.00	0.00

TOTAL OIL SPILL COSTS -	$	0.00	
NON-SPILL COSTS -	$	0.00	
- OIL SPILLS BACKED OUT -	$	0.00	
Total Net Social Cost -	$	0.00	Million
Net Social Cost per BBOE -	$	0.00	Million
Total Cost Incurred by Area Residents From Production in THAT Area	$	0.00	Million
Total Cost Borne by Area Residents From Production in ALL Areas	$	0.00	Million

NORTON

Resources (BBOE)

Oil - 0.00

Gas - 0.00

Total - 0.00

Oil Spills

	Number of Large Spills	Amount Spilled (Large and Small)
Coming Ashore -	0.00	0.00
Remaining at Sea -	0.00	0.00
Total -	0.00	0.00

TOTAL OIL SPILL COSTS -	$ 0.00	
NON-SPILL COSTS -	$ 0.00	
- OIL SPILLS BACKED OUT -	$ 0.00	
Total Net Social Cost -	$ 0.00	Million
Net Social Cost per BBOE -	$ 0.00	Million
Total Cost Incurred by Area Residents From Production in THAT Area	$ 0.00	Million
Total Cost Borne by Area Residents From Production in ALL Areas	$ 0.00	Million

KODIAK

Resources (BBOE)

Oil - 0.00

Gas - 0.00

Total - 0.00

Oil Spills

	Number of Large Spills	Amount Spilled (Large and Small)
Coming Ashore -	0.00	0.00
Remaining at Sea -	0.00	0.00
Total -	0.00	0.00

TOTAL OIL SPILL COSTS -	$ 0.00	
NON-SPILL COSTS -	$ 0.00	
- OIL SPILLS BACKED OUT -	$ 0.00	
Total Net Social Cost -	$ 0.00	Million
Net Social Cost per BBOE -	$ 0.00	Million
Total Cost Incurred by Area Residents From Production in THAT Area	$ 0.00	Million
Total Cost Borne by Area Residents From Production in ALL Areas	$ 0.00	Million

HOPE

Resources (BBOE)
Oil - 0.00
Gas - 0.00
Total - 0.00

Oil Spills

	Number of Large Spills	Amount Spilled (Large and Small)
Coming Ashore -	0.00	0.00
Remaining at Sea -	0.00	0.00
Total -	0.00	0.00

TOTAL OIL SPILL COSTS -	$	0.00	
NON-SPILL COSTS -	$	0.00	
- OIL SPILLS BACKED OUT -	$	0.00	
Total Net Social Cost -	$	0.00	Million
Net Social Cost per BBOE -	$	0.00	Million
Total Cost Incurred by Area Residents From Production in THAT Area	$	0.00	Million
Total Cost Borne by Area Residents From Production in ALL Areas	$	0.00	Million

SHUMAGIN

Resources (BBOE)
Oil - 0.00
Gas - 0.00
Total - 0.00

Oil Spills

	Number of Large Spills	Amount Spilled (Large and Small)
Coming Ashore -	0.00	0.00
Remaining at Sea -	0.00	0.00
Total -	0.00	0.00

TOTAL OIL SPILL COSTS -	$	0.00	
NON-SPILL COSTS -	$	0.00	
- OIL SPILLS BACKED OUT -	$	0.00	
Total Net Social Cost -	$	0.00	Million
Net Social Cost per BBOE -	$	0.00	Million
Total Cost Incurred by Area Residents From Production in THAT Area	$	0.00	Million
Total Cost Borne by Area Residents From Production in ALL Areas	$	0.00	Million

COOK INLET

Resources (BBOE)

Oil - 0.00

Gas - 0.00

Total - 0.00

Oil Spills

	Number of Large Spills	Amount Spilled (Large and Small)
Coming Ashore -	0.00	0.00
Remaining at Sea -	0.00	0.00
Total -	0.00	0.00

TOTAL OIL SPILL COSTS -	$	0.00
NON-SPILL COSTS -	$	0.00
- OIL SPILLS BACKED OUT -	$	0.00
Total Net Social Cost -	$	0.00 Million
Net Social Cost per BBOE -	$	0.00 Million
Total Cost Incurred by Area Residents From Production in THAT Area	$	0.00 Million
Total Cost Borne by Area Residents From Production in ALL Areas	$	0.00 Million

STR OF FLOR

Resources (BBOE)

Oil - 0.00

Gas - 0.01

Total - 0.01

Oil Spills

	Number of Large Spills	Amount Spilled (Large and Small)
Coming Ashore -	0.00	0.00
Remaining at Sea -	0.00	0.00
Total -	0.00	0.00

TOTAL OIL SPILL COSTS -	$	0.00
NON-SPILL COSTS -	$	0.32
- OIL SPILLS BACKED OUT -	$	0.00
Total Net Social Cost -	$	0.32 Million
Net Social Cost per BBOE -	$	53.07 Million
Total Cost Incurred by Area Residents From Production in THAT Area	$	0.32 Million
Total Cost Borne by Area Residents From Production in ALL Areas	$	0.27 Million

APPENDIX H

GEOGRAPHICAL, GEOLOGICAL, AND ECOLOGICAL CHARACTERISTICS OF PLANNING AREAS
OTHER USES OF THE OCS
LEASING AND DEVELOPMENT HISTORY OF AREAS
RELEVANT ENVIRONMENTAL AND PREDICTIVE INFORMATION

GEOGRAPHICAL, GEOLOGICAL, AND ECOLOGICAL CHARACTERISTICS OF PLANNING AREAS/OTHER USES OF THE OCS/LEASING AND DEVELOPMENT HISTORY OF AREAS/RELEVANT ENVIRONMENTAL AND PREDICTIVE INFORMATION

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GEOGRAPHICAL, GEOLOGICAL, AND ECOLOGICAL CHARACTERISTICS OF PLANNING AREAS OTHER USES OF THE OCS/LEASING AND DEVELOPMENT HISTORY OF AREAS RELEVANT ENVIRONMENTAL AND PREDICTIVE INFORMATION

I. Introduction

This Appendix describes the planning areas under consideration, focusing on their geographical, geological, and ecological characteristics. Other topics covered in this Appendix include other uses of the Outer Continental Shelf (OCS), the leasing and development history of planning areas, and relevant environmental and predictive information (a summary of the environmental studies program). Twenty-two planning areas are described, including two planning areas -- Straits of Florida and Washington-Oregon -- not previously included in the 5-year program.

This Appendix contains information which, according to section 18 (a)(2)(A) and (D) of the OCS Lands Act Amendments, must be considered in decisions regarding the timing and location of exploration, development, and production of oil and gas among the oil-and-gas-bearing physiographic regions of the OCS. This information concerns the geographical, geological, and ecological characteristics of OCS regions and the location of such regions with respect to other uses of the sea and seabed.

In addition to descriptions of planning areas, specific quantitative information is included in Tables H-1 through H-6. These tables present information concerning ecological characteristics, other uses of the sea and seabed, leasing and development history, environmental studies, and lease sale-specific environmental impact statement and oil-spill risk analyses by planning area. Maps showing the geographic location of planning areas are in Appendix M. Seismic information is included in Appendix E.

II. Geographical, Geological, and Ecological Characteristics of Planning Areas

This section provides brief planning area descriptions. These descriptions focus on the planning areas' broad geographical, geological, and ecological characteristics. More specific information is provided on each planning area's regional geology, petroleum potential, and on specific geologic features considered to be hazards or constraints to operations. Also, following each planning area description is a short list of supplemental readings for reference. A table showing some ecological characteristics of planning areas is on page H-59 of this appendix (Table H-1).

Certain geologic features and conditions may jeopardize offshore oil and gas operations. Such features are generally known as geohazards. High-risk conditions are classified as hazards; lower-risk conditions that can be mitigated more easily are generally classified as constraints. In areas where such geohazards exist, special engineering procedures may be necessary or stipulations may be imposed. Constraints are usually considered merely developmental conditions: once they have been identified, existing standard design and engineering technology can be used to minimize their adverse effects.

A. North Atlantic

The North Atlantic planning area includes Georges Bank and the Gulf of Maine on the continental shelf and extends seaward down the continental slope into deepwater on the continental rise. The slope shows some evidence of bottom instability while shifting sands, in the form of sand waves are common on the shelf. Strong currents are known to exist most of the year on the shallow portions of Georges Bank proper.

Average weather and sea conditions are not harsh, although extremes can cause navigation and other operational hazards. Reduced visibility due to fog is common during parts of the year.

The shoreline is primarily rocky, especially in the north, but scattered beaches occur throughout. Cape Cod and nearby islands are characterized by sandy shorelines. The major portion of the coastal area from Massachusetts south is intensely developed, but the actual shoreline is sparsely populated and undeveloped in many areas. Recreational and tourist use of the coastline is extensive.

Georges Bank is an area of high productivity and the site of spawning of commercially important species. Fisheries resources of the Bank, as well as fishery and other biological resources of submarine canyons, have been a major concern with respect to potential oil and gas activities. A biological stipulation is in force for all current leases in this area to ensure that appropriate monitoring is conducted and operations are conducted so as not to adversely affect biological resources. An interagency committee makes recommendations concerning implementation of the stipulation to the appropriate regulatory official. Another requirement applied in this area directs that oil and gas personnel be trained to recognize possible conflicts with fishing operations and to employ methods to reduce such conflicts.

1. Regional Geology

The North Atlantic planning area includes the Georges Bank Basin, the Gulf of Maine, and the deep water basin seaward of Georges Bank. The geology of the Georges Bank area consists of, as basic elements, pre-rift continental sediments capped by as much as 25,000 feet of syn- and post-rift marine and terrigenous deposits. The lithology appears mainly to be controlled by paleobathymetry and by distance from the ancient shorelines.

Pre- and syn-rift sediments are the erosional remnants of a thick section of Triassic and Paleozoic clastics, volcaniclastics, and freshwater deposits. These sediments are preserved in grabens and half grabens formed in crystalline and meta-sedimentary basement as a consequence of the rifting process. This graben fill was further faulted and deformed during several syn-rift orogenies. A regional erosional event subsequently planed off these sediments. This unconformity separates Triassic and older graben fill from overlying Triassic paralic sediments.

The rifting process continued in a number of distinct episodes from Late Triassic to Middle Jurassic time. Intrusion of marine waters after the initial rift resulted in the deposition of Late Triassic shallow marine and shoreline sediments including limestone, dolomite, and evaporites (mostly salt.) This section becomes enriched in clastics and coal to shoreward. Seaward, large

thicknesses of evaporites deposited in an arid shoreline environment were deformed by subsequent sediment loading and produced a number of diapirs in the northeastern part of the planning area. A widespread erosional unconformity caps the Triassic paralic/shallow marine sequences.

Renewed subsidence, probably associated with an early Jurassic rifting episode, resulted in the deposition of a widespread sand unit which was subsequently subaerially exposed. This unit is immediately above the Triassic unconformity. Rift-related tectonism ceased by Middle Jurassic when subsidence and sea level changes resulted in more open marine conditions and the consequent deposition of limestones. Some of these limestones were later altered to dolomite. Lowered sea level shortly after the beginning of the Late Jurassic produced a dramatic seaward shift in the limit of clastic sedimentation. Late Jurassic (and younger) sediments in the Continental Offshore Stratigraphic Test (COST) G-2 well are nearly totally clastics; sand, siltstone, and finer grained terrigenous deposits dominate the section.

Sea level has remained near its present level (except for short-term fluctuations) since about Late Jurassic time. Hence, Cretaceous and Tertiary sediments are nearly all sands, shales, and siltstones with occasional thin limestone beds.

Ocean basin subsidence relative to the continental margin had progressed to the point where a distinct shelf edge was formed by the middle of Late Jurassic time. This shelf edge provided a structural root for subsequent biohermal or reef development. The shelf edge complex including the carbonate buildup is discontinuously distributed parallel to the present shelf break throughout the planning area. Carbonate buildup persisted until some time in the Early Cretaceous when it ceased, probably because of sea level and/or climatic changes.

2. Petroleum Potential

Exploration for petroleum in the Georges Bank Basin began in April 1976 when the first of two COST wells was spudded. Eight additional wells were drilled by industry in 1981-82, all of which were dry.

The North Atlantic planning area can be conveniently divided into three areas of different hydrocarbon potential. These areas are the Gulf of Maine, Georges Bank Basin, and the deep water areas seaward of the continental slope. The petroleum potential of the Gulf of Maine and the deep water area is poorly understood because of limited data in those regions.

The most prospective part of the planning area is the Georges Bank Basin, a zone of thick sediments centered on the present shelf edge. This area includes the largest and most attractive exploration target in the North Atlantic--the Jurassic shelf edge (carbonate buildup). The carbonate buildup in the the Georges Bank area has not yet been drilled, but samples from equivalent strata to the northeast offshore of Canada (Scotian Shelf) had encouraging porosity and permeability, and showed evidence of hydrocarbons. Traps associated with the carbonate buildup are back-reef anticlines, stratigraphic pinchouts, and faulted anticlines and noses. The zone of thickest sediment also includes a zone of diapirs which trends southwest from the Canadian border.

Potential source and reservoir rocks in a number of wells have been analyzed. Source rock quality in terms of the type and quantity of thermally convertible kerogens is in the poor-fair range. Most of the kerogen is of terrestrial origin, and is thus considered gas prone.

Reservoir rocks in the thermally mature interval of the section tend to be tight with porosity ordinarily less than 5 percent. Sandstone as a distinct lithology is largely absent in the mature interval throughout most of the zone of thick sediments. Potential reservoir lithologies thus appear to be limited to limestones in which secondary porosity may have developed.

3. Geohazards

A number of geologic features found in the North Atlantic planning area present problems for drilling for oil and gas. When geologic features present problems that cannot be dealt with technologically, they are termed hazards; when geologic features present problems that can be reduced to an acceptable level, they are termed constraints. Hazards that have been noted in the North Atlantic are shallow gas, shallow faults, and sediment mass movement. Shallow gas occurs on the continental slope and shelf; shallow faults have only been reported to occur on the continental shelf. Neither shallow gas nor shallow faulting are major sources of concern as they rarely occur in the North Atlantic. The major hazard found here is sediment mass movement, which is found on the continental slope and upper rise. However, mass movement occurs quite often on the mid- and lower slope areas where slide features appear to be predominant. Canyons seem especially susceptible to mass movement; here the tidal currents are concentrated, undercutting the canyon walls, which weakens the sediment layers to the point where they slump, slide, or collapse into debris flows. Intercanyon areas are generally free from sediment mass movement with the exceptions of the slope in the vicinity of Alvin and Atlantis canyons and the vicinity of Munsen and Nygren canyons. The intracanyon mass movement is considered to be a contemporary process since there is no known present-day triggering mechanism, the intercanyon mass movement probably originated during Pleistocene glacial retreats, when large volumes of water and sediment were discharged onto the continental slope.

Buried channels, deep faulting, and erosion are the known constraints to drilling in the North Atlantic. Erosional constraints are posed by the presence of sand waves on Georges Bank proper. Constraints are more widespread in occurrence than the hazards. Buried channels are quite common and numerous on the Georges Bank Shelf and Slope, a few deep faults occur throughout the North Atlantic, and erosion occurs mostly on Nantucket Shoals, Georges Bank, and possibly along the continental rise. No data exist to confirm erosion on the continental rise but high-velocity currents have been recorded on the rise south of Nova Scotia.

4. Supplemental Reading

Carpenter, G. and Amato, R., 1984, Geology report: proposed North Atlantic OCS Oil and Gas Lease Sale N. 96: U.S. Minerals Management Service OCS Report 84-0062, 19 p.

Klitgord, K., Schlee, J., and Hinz., K., 1982, Basement structure, sedimentation and tectonic history of the Georges Bank Basin, in P. Scholle and C. Wenkam, eds., Geological studies of the COST Nos. G-1 and G-2 wells, United States North Atlantic Outer Continental Shelf: U.S. Geological Survey Circular 861, P. 160-186.

Miller, R., Lerch, H., Claypool, G., Smith, M., Owings, D., Ligon, D. and Eisner, S., 1982, Organic geochemistry of the Georges Bank Basin, COST Nos. G-1 and G-2 wells in P. Scholle and C. Wenkam, eds., Geological studies of the COST Nos. G-1 and G-2 wells, United States North Atlantic Outer Continental Shelf: U.S. Geological Survey Circular 861, p. 105-142.

Poag, C. W., 1982, Stratigraphic reference section for Georges Bank Basin - depositional model for New England passive margin: American Association of Petroleum Geologists Bulletin, v. 66, no. 8, p. 1021-1041.

Ziegler, D., 1983, Hydrocarbon potential of Newark Rift System, eastern North America: American Association of Petroleum Geologists annual meeting abstracts and program, v. 67, p. 574-575.

B. Mid-Atlantic

The Mid-Atlantic planning area includes three major physiographic regions -- the continental shelf, the continental slope, and the continental rise. Large variations in both topographic and bottom stability along the slope are the chief potential geologic hazards. Meteorologic conditions are similar to those further north, though fog is generally not a problem in this area. Internal waves along the slope are of concern to drilling operations. High seas occur in winter and during tropical storms.

The shoreline is primarily beach, with extensive wetlands behind barrier islands, which are important spawning and nursery areas for the shellfish industry and other fisheries. Barrier beaches and wetlands of New Jersey, the Delmarva Peninsula and North Carolina (Outer Banks) are extremely important. While the coastal area between New York and Baltimore is urbanized, the shoreline, with a few exceptions, is characterized by low density development. Much of the beach front is built up with residential, including seasonal, dwellings and commercial development related to recreation and tourism. However, there are also protected, undeveloped shoreline areas. Recreation and tourism use of the shorelines is high.

Submarine canyons and a large commercial fishery are characteristic of the planning area, although the fishing activity is more dispersed than on Georges Bank. Stipulations to protect canyon resources and reduce conflicts with fishing, similar to those used in the North Atlantic planning area have also been utilized in this area.

1. Regional Geology

The Baltimore Canyon Trough is the major geologic feature of the Mid-Atlantic planning area. It consists of an elongated Northeast-trending depression averaging 100 miles in width and extending from roughly Virginia Beach to Long Island. Sediment thickness in this basin exceeds 50,000 feet. The included sediments range in age from Triassic to Recent with most of the Section being of Jurassic age.

Pre-rift and syn-rift sediments (Triassic and older) occur in a NE-SW trending series of grabens and half-grabens which developed in basement rock as a result of the rifting process. Pre-rift rocks also cover unfaulted crystalline and meta-sedimentary basement over much of the planning area. These sediments

are preserved as erosional remnants and consist primarily of continental clastics, volcanics, evaporites, and freshwater deposits. Pre-rift sediments are capped by a prominent regional erosional unconformity (the breakup unconformity) which is well defined on seismic data.

Rift-related tectonism ceased by lower Jurassic time and the post-rift intrusion of marine waters resulted in deposition of shallow water, oolitic limestones, The limestones are interbedded by marginal marine clastics and swamp deposits. Much of the Jurassic section in the COST B-2 and B-3 wells resembles the classic coal cycle (cyclothem) of marsh deposits grading into shallow marine lithologies. Paleo sea level apparently remained near the position established in Jurassic time until well into the Cretaceous as evidenced by coal beds in that part of the section.

Rifting had progressed to the point where the present shelf/basin structural configuration had developed in Jurassic time. The resulting shelf edge became a locus for "reef" growth in the Jurassic and ended in the Early Cretaceous when growth ceased, probably because of climatic or sea level changes. The upper, seaward face of the reef is cut by a prominent erosional unconformity which may have resulted in development of secondary porosity in that portion of the reef.

Salt deposition, probably near the beginning of the post-rift phase, resulted in scattered occurrences of deep-seated salt diapirs. The "Texaco-Tenneco" structure (Blocks 598, 599, 642, 643), about 30 miles Southwest of Hudson Canyon, may have a salt core. Other, scattered intrusives are sparely distributed throughout the planning area. The largest structural feature in the Baltimore Canyon Trough (Stone Dome), is believed to be an igneous plug.

Cenozoic sediments consist mostly of poorly consolidated sands, mudstones, clays, and marls deposited in shallow water. Relatively deep, open marine conditions prevailed for most of the Eocene, and resulted in the deposition of a thick sequence of limestones which grade into marls and calcareous mudstones to landward. Surface sediment is mostly sand and unconsolidated mud.

2. Petroleum Potential

The first deep stratigraphic test well (COST B-2) in the Mid-Atlantic planning area was drilled in 1976. COST B-3 was drilled in 1978 and was followed by 32 industry exploratory wells. Except for five wells drilled on a single large structure (Texaco-Tenneco structure) which discovered significant quantities of gas and condensate, all the industry wells were dry. (The B-3 well, located about 30 miles southwest from this structure encountered a show of gas from a 6-foot zone below 15,000 feet.)

The most prospective part of the Mid-Atlantic planning area is the zone of thick sediments in the Baltimore Canyon Trough. The "Reef Trend" and its associated fore and back reef structures are considered part of this zone. Several wells drilled in 1984 on and near the reef were dry.

Potential source and reservoir rocks in a number of wells have been analyzed. Source rock quality is generally in the poor-to-good range with regard to the type and quantity of proto-hydrocarbons. Much of the kerogen is terrestrial in origin indicating most of the generated hydrocarbons would be gas rather than

oil. Presumably, the potential for oil would increase to seaward where the proportion of algal, oil-prone kerogen would be expected to increase. In the sedimentary section in the Baltimore Canyon Trough that is considered thermally mature for hydrocarbon generation, source rock shales tend to be lean in organic matter (usually less than one percent).

Reservoir rocks below 10,000 feet are limited to sandstones with relatively low porosity and permeability. Some development of secondary porosity by dolomitization of limestones has been observed, but is considered only of local significance. Well log interpretations show that only a small fraction of the total sand thickness below 10,000 feet has porosities greater than five percent. Permeability is low because of infilling of intergranular voids by calcite cement and contamination by clay-silt sized sediment.

3. Geohazards

Sediment mass movement is the major geologic process which could be hazardous to oil and gas drilling in the Mid-Atlantic planning area. Mass movement, restricted in occurrence to the continental slope and rise, is considered the dominant process shaping the submarine canyons. The canyons serve to focus tidal currents and possible Gulf Stream eddy currents which, in conjunction with bioerosion, undercut the canyon walls, weakening the sediment layers to the point that they slump, slide, or collapse into debris flows. There is evidence that this is a present day process in many of the canyons; however, for unknown reasons, some of the canyons appear to be quiescent. The intercanyon ridges show evidence of widely scattered mass movement. The area between Mey and Hudson Canyons seems to be an exception. The majority of the slope in this area has undergone some kind of mass movement, most of which consists of differential compactions. Most authors indicate that intercanyon mass movement features are probably Pleistocene in age and not a contemporary process. Additional hazards which have been noted in the Mid-Atlantic are very widely scattered. Shallow faulting of apparently recent occurrence has been observed on the shelf and slope and shallow gas has been noted on the shelf, slope, and rise. The most widespread potential for shallow gas may be in the zone of clathrates (frozen gas hydrates) which occurs along the continental rise from 2,500 m to 3,800 m deep. Clathrates can cap gas deposits that are overpressured.

Other geologic features found in the Mid-Atlantic area that can have adverse effects on drilling are seafloor scour, filled channels, shallow faults (with no recent movement), and gassy sediments. These features occur only locally and are considered constraints as current drilling technology can reduce the adverse effects to an acceptable level.

4. Supplemental Reading

Amato, R., and Simonis, E., eds., 1979, Geologic and operational summary COST N. B-3 well, Baltimore Canyon Trough area, Mid-Atlantic OCS: U.S. Geological Survey Open-File Report 79-1159, 118 p.

Carpenter, G. and Amato, R., 1984, Geology Report: proposed Mid-Atlantic OCS Oil and Gas Lease Sale No. 111, U.S. Minerals Management Service OCS Report 84-0022, 16 p.

Giordano, A., Carpenter, G. and Amato, R., 1984, Oil and gas developments in Atlantic Coastal Plain and Outer Continental Shelf in 1983: American Association of Petroleum Geologists Bulletin No. 10, p. 1407-1411.

Miller, R., Schultz, D., Claypool, G., Smith, M., Lerch, H., Ligon, D., Owings, D. and Gary, C., 1980, Organic geochemistry, in United States Mid-Atlantic Continental Slope area: U.S. Geological Survey Circular 833, p. 85-104.

Weeks, L. G., 1974, Petroleum resources potential of Continental Margins, in The Geology of Continental Magins, C. A. Burke and C. L. Drake eds: Springer-Verlag, p. 953-964.

C. South Atlantic

The most promising geologic features of the South Atlantic lie close to the shoreline in the vicinity of Cape Hatteras, but otherwise prospective areas are located roughly 25 to 75 miles offshore from the coastline. Geohazards include historic seismicity, localized bottom instability, scouring, and faulting. Strong currents of the Gulf stream and its eddies prevail.

The South Atlantic experiences hurricanes with regularity, which probably present the greatest weather hazard to offshore operations in the area.

The shoreline is characterized by extensive barrier islands backed by wetlands. The wetlands are an important habitat for coastal birds as well as spawning grounds for fish and shellfish and important nesting areas for marine turtles. The endangered manatee inhabits the coastal waters. Extensive beds of submerged aquatic vegetation also occur in the South Atlantic and are of particular importance to the shrimp industry.

Although the submarine canyons that can be found further north do not exist south of Cape Hatteras, some especially productive marine communities exist in the vicinity of rocky formations or other hard substrate--known as live bottoms. These include coral reef structures. Stipulations have been developed and applied in the past to protect these resources, including requirements for monitoring, restrictions on disposal of drill cuttings and fluids, and possible relocation of drilling operations.

Industrial use of the coastline, including major ports, is characteristic of urban areas, and some portions of the coast are quite well developed for recreation and tourism use, including significant barrier island development. Nonetheless, large stretches of coast are relatively undeveloped.

1. Regional Geology

The South Atlantic Planning Area contains three major sedimentary basins: the Carolina Trough, Southeast Georgia Embayment, and the Blake Plateau Basin. The geology of the South Atlantic is less well known than other planning areas mainly because it has the largest number of major basins and the fewest wells (7). The industry exploration effort has been concentrated in the Southeast Georgia Embayment, the smallest, and geologically, the least attractive sedimentary basin.

The most important rocks in the Atlantic OCS for hydrocarbon exploration are of Jurassic age. Jurassic rocks are absent in the Southeast Georgia Embayment and the sedimentary section is generally only about 10,000 feet thick. The lower, thermally mature part of the section is largely composed of Cretaceous continental clastics with poor source rock characteristics. These sediments rest on an unconformity above Paleozoic meta-sedimentary basement rocks. Sediments are flat lying (essentially a submerged coastal plain), and include few large structural traps.

The Carolina Trough is a narrow, linear basin approximately 280 miles long and 25 miles wide which contains over 30,000 feet of sedimentary fill. The rocks range in age from Triassic to Recent with most of the section being of Jurassic age. The Carolina Trough has never been drilled, but seismic data indicate that the Triassic rocks are probably continental clastics deposited prior to ocean basin rifting. The Jurassic rocks are probably limestones and dolomites with clastic interbeds. The carbonates either grade landward to clastics or pinchout entirely. The Cretaceous and younger sediments are believed to be mostly sand and shale with carbonates occurring as a second order component in clastic rocks, e.g. marls, clacareous mudstones, etc.

The Blake Plateau Basin is the largest sedimentary basin off the U.S. East Coast. There are no deep exploratory wells in the basin but speculations regarding the probable lithologies have been made. Most of the basin is probably floored by basement generated during the rifting process. Sediments above basement are mostly limestones and dolomites, which are over 30,000 feet thick in the axis of the basin. Well over half of the total thickness is Jurassic in age with most of the remainder being Cretaceous. Basin subsidence had apparently ceased by the close of the Cretaceous period, since the Tertiary section is extremely thin. The surface of the Blake Plateau is swept by strong bottom currents that currently prevent further deposition.

2. Petroleum Potential

The petroleum potential of the South Atlantic Planning Area is poorly known, largely due to the lack of exploratory well data. The first deep well in the planning area was the COST GE-1, which was completed in 1977. This was followed by six industry wells spudded in 1979 in the Southeast Georgia Embayment, all of which were dry. Geological analyses of these wells indicate limited hydrocarbon potential, therefore, the probability of further exploratory drilling in this basin is probably slight.

The Carolina Trough appears to offer good potential for hydrocarbon generation and retention. It has sufficient sediment thickness to ensure an interval of thermal maturity, a large number of attractive traps, and the section may include oil-prone source rocks. A thick regional salt bed, deposited immediately after rifting ceased, has been deformed by sediment loading, producing a number of diapirs on the seaward edge of the basin. A growth fault on the continental slope associated with salt flow may provide other traps. Other faults are common within and on the margins of the basin.

The Blake Plateau Basin may offer attractive possibilities for commercial accumulations of hydrocarbons. The basin is large in area and may contain thermally mature marine sediments that may be oil-prone rather than gas-prone because of the presence of algal kerogens. The basin probably has been tectonically stable since Lower Jurassic time, as the sediments appear unaffected

by faulting or deformation. The few structures identified tend to be large with very low relief. A carbonate buildup trend is evident, but is Cretaceous in age and probably thermally immature.

Federal leasing has never been conducted in the Straits of Florida. Because of this, geophysical data coverage and well-derived geological information are not as complete as for other areas with relatively long leasing histories. Some generalizations on the potential for generation and retention of hydrocarbons on a regional level can still be made from a few wells drilled onshore and in State waters of Florida and in the Bahamas.

Sediment thickness is variable throughout the region to a maximum of about 37,000 feet. Wells drilled in Bahamian waters indicate much of the section has been flushed by circulating water. This has resulted in locally excellent porosity (occasionally cavernous) but has also driven any in-situ hydrocarbons out. Much of the limestone in the deeper parts of the section has been altered to dolomite which can also result in significant improvement in secondary porosity.

Deposition of evaporites in the Jurassic does not appear to have resulted in large numbers of diapiric structures. Anhydrite and halite beds may be too thin or lack the overburden required to induce plastic flow.

3. Geohazards

Geological features hazardous to drilling are very sparse in shallow water areas of the South Atlantic. Hazards to drilling are fairly prevalent in the deepwater areas of the region where mass movement features, active faults, and clathrates (frozen gas hydrate) exist. The lack of a steep, canyon-incised slope and the low sedimentation rate in much of the area, due to the Gulf Stream sweeping the seafloor clean, eliminates much of the sedimentary environment in which geohazards are most often found. Hazards that do exist in the South Atlantic are surficial sediment collapsed into cavernous (karst) topography, sediment mass movement, and shallow gas. The collapse of surficial sediments has been observed on the shelf of northern Florida and Georgia in places where portions of shallow carbonate rocks have dissolved, leaving the surficial sediments without support. Similar conditions exist on the Blake Plateau where the presence of shallow karstic carbonates could result in surface collapse. With the ubiquity of carbonates in the South Atlantic, there is the possibility that surficial sediment collapse may be a problem in other areas as well as those just mentioned. A true continental slope occurs along the eastern portions of the Carolina Trough and Blake Plateau. Mass movement appears to be common throughout the slope, particularly between 35° N. and 31° N. latitudes. Those mass movements that have occurred appear to be fairly recent. A major growth fault occurs along the eastern edge of the Carolina Trough and Blake Platform. This fault is related to salt diapirism and, as such, appears to be active. The potential for shallow gas is highest on the slope and upper rise of the eastern Blake Plateau where clathrate (frozen gas hydrate) layers can act as caps, forming shallow gas pockets. These clathrate layers extend northward through the eastern end of the Carolina Trough and into the Mid-Atlantic region. Therefore, potential for shallow gas exists throughout the extent of the clathrate layers.

Few surveys have been done in the Florida Straits, so there is little direct evidence concerning the presence or absence of hazardous geological conditions. The most likely hazard to be encountered would be surficial sediment

collapse due to the near surface karst conditions on the Miami Terrace. With the prevalence of carbonates in the Straits of Florida, surficial sediment collapse could occur in other areas of the Straits as well.

Of the various constraints to drilling found in the South Atlantic (i.e., scour, shallow buried faults or deep faults, filled channels, and gassy sediments), the most notable is scour. Cape-associated shoals are highly mobile and areas of the outer shelf, slope, and Blake Plateau are intensely eroded by the Gulf Stream and associated currents. Shallow buried faults are common in parts of the South Atlantic. These features could act as conduits for overpressured gas if the two features occurred in conjunction with each other.

A major constraint exists in the Straits in the form of scour. Sandy areas of the Straits are readily scoured by vigorous Gulf Stream activity. Other constraints that may exist are shallow faults, filled channels, and gassy sediments.

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D. Straits of Florida

The Straits of Florida planning area includes the Florida Keys, Florida Bay, Biscayne Bay, and southern Florida coastal and offshore region up to the southern boundary of the South Atlantic planning area (28° 17'10" N. latitude). The planning area consists of a very shallow shelf area that is very large (spatially) north and west of the Keys and the Dry Tortugas, and very narrow to the south and east. The continental slope south and east of the Keys is fairly steep.

The Straits of Florida could be affected by tropical storms or hurricanes slightly more than the remainder of the Gulf of Mexico because of a preferred path between Cuba and Florida over the warm waters of the area.

The mainland coast of the Straits of Florida is composed of mangrove and marsh areas with little or no urban development. The Keys, however, are relatively well developed with tourist oriented commercial and residential land use. Preservation areas exist in the Straits including Everglades National Park and numerous State recreation areas.

Several endangered and threatened species occur in the Straits of Florida planning area: critical habitats of the Florida manatee, American crocodile, and Cape Sable sparrow; American alligator; Key deer; Key Largo cotton mouse and wood rat; right, fin, humpback, sei, and sperm whales; bald eagle, and peregrine falcon; wood stork; green and loggerhead sea turtles; Schaus swallowtail butterfly; Atlantic salt marsh snake; and Key tree cactus.

1. Regional Geology

The continental shelf and slope is a continuation of the Florida platform, which is composed of Mesozoic-Cenozoic carbonates. The Florida Straits shelf area has been removed since Mesozoic times from the major locus of rapid sedimentation. In particular, Pleistocene sediments which attain great thicknesses over the continental shelf of the rest of the northern Gulf of Mexico are virtually nonexistant in the Florida Straits shelf. The South Florida Keys are swept along their southern edge by the Gulf Stream. The higher features of the shelf are Pleistocene coral and oolite reefs. The higher of these reefs are emergent as the Florida Keys and extend from the Marquesas to Key Biscayne.

The dominant lithologies of the Straits of Florida area are carbonates deposited in an unnamed basin encompassing southeastern and southern Florida and the Bahamas. The post-Triassic section is nearly totally chalks, limestones, dolomities, and unconsolidated lime muds of shallow water origin. Evaporites and chert are important secondary lithologies. Triassic (and perhaps Lower Jurassic) rocks are arkosic sandstones and volcaniclastics deposited in grabens and half grabens developed in Paleozoic/Mesozoic crystalline basement as a consequence of rifting. These rocks are separated from the overlying Jurassic and younger carbonates by a prominent regional unconformity.

2. Petroleum Potential

Although a considerable thickness of carbonate strata is present in the Florida Straits, the straits is lacking in carboniferous bearing strata and structural traps. The hydrocarbon bearing potential for the Florida Straits has to be considered low.

The petroleum potential of the Straits of Florida region is difficult to assess. Test well results have produced only spotty indications of hydrocarbons, but analogous, carbonate provinces (i.e., the Middle East) have enormous production.

Commercial hydrocarbon accumulations have not yet been discovered in the Florida Straits region but minor production occurs in areas peripheral to the region (northwest coast of Cuba, Sunniland trend in central Florida). These small fields produced from carbonate reservoirs of Jurassic age and the oil and gas may have originated from carbonate source rocks. (Carbonates are not commonly considered to be good source rocks).

Sediment thickness is variable throughout the region to a maximum of about 25,000 feet. Wells drilled in Bahamian territory indicate much of the section has been flushed by circulating water. This has resulted in locally excellent porosity (occasionally cavernous) but has also driven out any in-situ hydrocarbons. Much of the limestone in the deeper parts of the section has been altered to dolomite, which can result in significant improvement in secondary porosity.

Deposition of evaporites in the Jurassic has not produced large numbers of diapiric structures. Anhydrite and halite beds may be too thin or lack the overburden required to induce plastic flow.

3. Geohazards

The southern Straits of Florida (from 26° South) have complex geologic structure with a resultant geomorphologic environment that includes several seafloor processes: slumping, growth faulting, down-to-the-basin tectonic faulting, solution-formed karst, and possibly submarine currents. The northern Straits of Florida, from 26°N to 28°N, have a simpler geologic history and structure. The major process of concern here is solution-formed karst. The Pourtales Terrace in the southern straits and the Miami Terrace in the northern straits have very rugged and complex topographies that are the result of carbonate solution and the formation of sinkholes. The faulting in the southern straits has produced a very steep slope and several escarpments tens of meters high. Whether the faulting, either the shallow or deep, is active at present is not known. In some areas of the southern straits the slumping along the over-steepened Florida escarpment appears to have been possibly post-Pleistocene.

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E. Eastern Gulf of Mexico

The Eastern Gulf of Mexico planning area is situated off the western or Gulf coast of Florida. This planning area is characterized by numerous potential hydrocarbon structures, which are distributed throughout the planning area. Submarine karst topography, especially along either shelf break, is a potential geologic problem to be faced for oil and gas operations.

Tropical storm activity is the dominant weather factor affecting operations. The Loop Current has considerable influence on water velocities in a large part of the Eastern Gulf.

As in the South Atlantic, the seafloor in the Eastern Gulf is characterized by scattered patches of hard substrate which often support highly productive communities of coral, fish and other marine resources, depending on water depth. The best known is the Florida Middle Grounds. Stipulations like those developed to protect similar resources in the South Atlantic have been developed to protect such biological resources in the Eastern Gulf.

The coastline consists of marshes, mangrove swamps, mud flats and lagoons, sometimes fronted by beaches and barrier islands. Extensive beds of submerged aquatic vegetation occur in the Eastern Gulf of Mexico. These are of particular importance to the shrimp industry. The shoreline is relatively undeveloped, but heavily used for recreation and tourism. Commercial fishing as well as tourism is of economic importance.

Several endangered and threatened species occur in the Eastern Gulf planning area: critical habitats of the Florida manatee, Choctawatchee beach mouse, and Perdido Key beach mouse; bald eagle; peregrine falcon; wood stork; right, fin, humpback, and sperm whales; Kemp's ridley, green, hawksbill, leatherback, and loggerhead sea turtles; American alligator; and Okalossa darter.

1. Regional Geology

The Eastern Gulf of Mexico (EGOM) Planning Area lies offshore from the States of Alabama and Florida. Physiographically the area is mainly underlain by the West Florida Shelf, Terrace, and Escarpment which constitute the Florida carbonate platform and is composed of a thick Mesozoic-Cenozoic sequence of primarily carbonate bank deposits. The western margin of the area consists of the terrigenous clastic province of the Mississippi/Alabama/DeSoto Slope, Mississippi Fan, and Florida Plain. Very few wells have been drilled in the EGOM so that most of what is known about the stratigraphy has been inferred from seismic records and by projection from on shore.

Prospective hydrocarbon traps in the northwest portion of the EGOM are primarily in extensions of Jurassic and Cretaceous trends from the north. The Destin Anticline is a large (12 x 50 miles), NW-SE trending structure formed over a salt swell. Several dry holes were drilled on the eastern portion of this

structure but excellent reservoir rocks were found in the Norphlet formation (Upper Jurassic). The crest of the structure is presently being explored and is still considered to have potential. There is a field of salt diapirs (DeSoto Diapir Field) located southwest of Destin that has not been tested yet which has hydrocarbon potential.

The middle Ground Arch is a NE-SW trending high lying between the Suwanee Basin and the Central Florida Trough. Potential targets are structural and stratigraphic traps in Jurassic strata onlapping Paleozoic metamorphic rocks around the edge of the Middle Ground Arch.

The Central Florida Trough is a westward plunging basin with more than 16,400 feet of pre-Middle Cretaceous sediments near the edge of the Florida Scarp. Potential targets are structural and stratigraphic traps in Jurassic and Lower Cretaceous strata onlapping Paleozoic igneous and metamorphic rocks.

The Central Florida Arch received less sediments than the troughs to either side. There should however, be potential structural and stratigraphic traps in the shelf and slope areas.

The South Florida Basin encompasses an area of about 75,000 square miles and extends from the Peninsula Arch on the east to the Florida Escarpment on the west. Eleven oil fields have been discovered in this basin on the Florida mainland. The fields are associated with magnetic highs and noses on the north-eastern rim of the basin. Production occurs between 11,320 and 11,890 feet. The offshore part of the basin has not been fully tested and could be prospective.

The West Florida slope consists of the West Florida Terrace and West Florida Escarpment, which extend from the DeSoto Slope south to the Straits of Florida The escarpment is a constructional slope built up of shelf edge carbonate deposits and reef growth during Early Cretaceous time. Samples from the area show a lack of high energy facies indicating that the escarpment is an erosional feature. Limestones and deep water chalks ranging in age from Late Cretaceous through Pleistocene unconformably overlie older, shallow water carbonates. The DeSoto Slope in the northwestern part of the EGOM is underlain by a thick sequence of sediments folded and arched by isolated salt domes and pillars. Regional growth faults parallel the shelf edge and may contain traps on the down-thrown side. Peripheral and radial faulting associated with salt structures may contain potential traps.

The Mississippi Fan is a broad, thick arcuate accumulation of Pleistocene, shallow water sediments extending nearly 375 miles from the Mississippi Delta to the abyssal plain. It covers an area greater than 111,970 square miles and is 2.8 miles thick in its thickest portion. It consists of a series of coalescing fan lobes. Thick sand sequences are present and the hydrocarbon potential is as yet untested.

2. Petroleum Potential

The EGOM is primarily a carbonate province. There is production onshore in the South Florida Basin from the Lower Cretaceous Sunniland Formation. Production also occurs in the Florida Panhandle from Jurassic sediments. As of September 1, 1985, 27 wells have been completed in the EGOM and at present there is no offshore production.

Source rocks in the EGOM are predominantly marine shales and organic rich carbonates ranging in age from Jurassic to Cretaceous. Cenozoic rocks may be important sources in deeper water. Tertiary sediments do not appear to have a promising suite of source rocks. Reservoir rocks range in age from Jurassic to Cretaceous. Jurassic reservoir rocks are primarily grain supported wakestones, packstones and grainstones, dolomites and some mudstones. Prospective Cretaceous reservoir rocks are deltaic and turbidite sandstones, carbonate reefs developed on the landward side of positive blocks and shell zones. Many potential traps exist in the EGOM including anticlines and faulted anticlines, structural closure against normal and growth faults, and a variety of stratigraphic and reef traps.

3. Geohazards

There are five kinds of geologic features in the EGOM which could become potential hazards: carbonate buildups, karst topography, channelization, seafloor instability and sand movement.

Carbonate buildups occur southwest of Middle Ground Reef. Six north-south trending ridges occur in water depth of 120-240 feet. They may be analogous to geomorphic spits with reef deposits on top. The largest lies due west of Tampa and is called the Elbow. Farther to the south a similar feature called Howell Hook occurs. Another series of reefal ridges is located along the shelf edge. Carbonate buildups in the form of pinnacle reefs are located near the shelf break bordering DeSoto Canyon. Individual coral heads occur on the inner shelf.

Karst structures are located in two bands on the inner shelf with the innermost being coincident with the locations or reported sinks and springs. The outer belt is 5 miles wide and 50 miles long. Well dissected solution features are distributed in a 12 mile wide band in the central shelf interspersed with the Middle Ground reefs. There are also karst features adjacent to Pulley Ridge on the south. Isolated karst features are buried under the outer shelf. Large, well developed channel complexes occur in the central shelf extending from Tampa to south of Charlotte Harbor.

A large mass of sediment at the base of the slope at 26°N has been identified as a massive slump apparently the result of sediment overloading on the Upper Slope resulting in sea floor instability. The sediment source appears to be due to high productivity created by upwelling of nutrients related to impinging of the loop current on the slope. While the bulk of the inner shelf sediments appear to be relict, the shelf edge appears to be a major depocenter for recent sediments and therefore conditions for mass wasting exist. Sediment slumping is presently occurring on the upper slope from 25°40'N to 25°N. Block slides have occurred on the Central Slope south of 26°N.

There are six major areas of mobile sand in the EGOM. The first area parallels the West Florida Peninsula out to water depths of 60 feet and is characterized by giant to large scale bed forms. The second area is located in the shallow water region of the Big Bend area out to mid shelf. The topography consists of low relief swells and scattered giant to largescale bed forms. Area three extends north and south of the Middle Ground out to water depths of 180 feet and has small scale features. The fourth area is situated near Cape San Blas and consists of giant sand waves out to depths of 130 feet and small scale bed forms out to 270 feet of water. Area five covers the outer shelf and ranges

from low relief swells to large scale bed forms. A sixth area of giant sand waves is located between Howell Hook and the shelf break. Faulting is not well documented in the Eastern Gulf and in fact may not be significant as potential hazards in the EGOM.

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F. Central Gulf of Mexico

The Central Gulf of Mexico planning area is situated off the coasts of Alabama, Mississippi, and Louisiana. This planning area is characterized by many small hydrocarbon producing structures, dispersed throughout the area. Many more potential hydrocarbon structures exist in deeper waters of the continental shelf and slope. Mudflows and slumps in the Mississippi Delta vicinity and along the continental slope and gas-charged sediments are the greatest geologic hazards to offshore development. Hurricanes are the weather factor most influencing operations and facility design.

Several endangered and threatened species occur in the Central Gulf planning area: critical habitats for the Alabama and Perdido Key beach mice, and Mississippi sandhill crane; fin, humpback, sei, and sperm whales; Eskimo curlew; bald eagle; peregrine falcon; brown pelican; American alligator; and Kemp's ridley, green, leatherback, and loggerhead sea turtles.

Extensive wetlands, vital for production of the valuable Gulf coast commercial fish and shellfish, are the dominant coastal features. These are also important for wintering birds. However, the coastal zone of this planning area also supports the greatest extent of oil and gas infrastructure in the U.S., if not the world, and hosts extensive commercial shipping in its ports (New Orleans, Mobile) as well.

Offshore, scattered topographic high features correspond to areas of especially high productivity, including fisheries resources. These features are similar to those in the Western Gulf and special stipulations, like those applied in the Western Gulf, have been used to protect them. This area supports a large commercial fishery.

1. Regional Geology

The Central Gulf of Mexico (CGOM) Planning area encompasses the Continental Shelf off the Louisiana Coast, the area east of the Mississippi Delta off the Mississippi and Alabama coasts to the eastern edge of Mobile Bay and the deeper water areas of Mississippi Canyon, Atwater Valley, NG 16-4, Green Canyon and Walker Ridge. The area is largely a Mesozoic-Cenozoic Basin with a series of thick Cenozoic depocenters which have shifted seaward with time to a Pleistocene depocenter at the shelf edge.

Structural deformation in the Gulf of Mexico since mid-Cretaceous time has been primarily in response to heavy sediment loading. Mesozoic and Cenozoic sediments have been upwarped, folded, and diapirically penetrated by plastic flowage of thick Jurassic salt deposits. Large contemporaneous or growth faults are also major structural features of the CGOM. Peripheral and radial faulting are typically associated with diapirism. Structural and stratigraphic traps are usually controlled by one of these features. In some areas undercompacted shales have deformed plastically in a manner similar to the salt and are responsible for some of the mounding and diaprism in various locations.

The geologic province of the CGOM is composed of a thick sequence of clastic sediments deposited in offlapping wedges that have been deformed by the movement of salt and undercompacted shale during Cenozoic time. Older Mesozoic trends occur in Late Jurassic reservoirs which extend across southern Mississippi and Alabama and into State waters near Dauphin Island, Alabama. Recent drilling has confirmed the extension of this trend southeastward into the Federal Outer Continental Shelf (OCS). There are several prospects of Jurassic age located in the very northeastern part of the CGOM. Oil and gas presently are being produced onshore from Lower Cretaceous sandstones and carbonates along a trend from Texas to southwestern Alabama. Prospective Lower Cretaceous reservoir rocks probably occur under the OCS off Mississippi and Alabama in the form of deltaic and turbidite sandstones, carbonate reefs and shell zones. Deep Tuscaloosa sands of Upper Cretaceous age extend in a band across south Louisiana and are prolific gas producers. This deep Tuscaloosa gas trend may extend southeastward across the eastern Louisiana/Mississippi continental shelf and slope.

Throughout Cenozoic time clastic sediments poured into the Gulf of Mexico Basin from the north and west. There are five major producing trends in the CGOM: Lower Miocene, Middle Miocene, Upper Miocene, Pliocene and Pleistocene. Prior to the Miocene the major source of sediment supply was from the west carried by the ancestral Rio Grande and Brazos River systems. As the major supply of sediment shifted to the north and the Mississippi River system became the major sediment carrier so too the major depocenters shifted to the northern rim of the Gulf. The oldest producing Cenozoic horizon in the CGOM is Lower Miocene. Miocene production extends from east of the Mississippi Delta into the Western Gulf of Mexico (WGOM) Planning Area. Production is primarily from deltaic sands. There was a gradual southward shift of depocenters during the Lower, Middle, and Upper Miocene. The maximum accumulated sediment thickness exceeds 20,000 feet. Pliocene sediments were also deposited in a deltaic environment and attained an aggregate thickness of 8,200 feet. Production extends from east of the Mississippi Delta into the High Island areas in the WGOM Planning Area. Pliocene production also continues beneath the Pleistocene in the Pliocene/Pleistocene producing trend.

The Pleistocene depositional environment was similar to the Miocene/Pliocene. Although numerous small transgressions and regressions occurred, in general, regression prevailed. There was a large increase in sediment supply from the glaciated areas to the north. The Pleistocene depocenter lies along the shelf edge south of Louisiana where 15,000 feet of Pleistocene sediments have been penetrated. Total thickness may exceed 20,000 feet. Pleistocene production will probably exceed all other producing horizons.

Many large structures occur on the continental slope which forms the southern part of the CGOM. Production has already been established at several locations on the slope in water depths approaching 1,000 feet. The area is underlain by Pleistocene and Pliocene sediments and structures, which were formed in response to sediment loading on the underlying salt and shale.

2. Petroleum Potential

The CGOM includes the very mature region of the Louisiana shelf and the frontier areas of the Mississippi-Alabama shelf and the deep water slope province. The CGOM contains approximately 450 oil and gas fields which range in age from Miocene to Pleistocene.

Source rocks for the CGOM consist primarily of organic rich shales which range in age from Lower Cenozoic through Pleistocene. Potential Mesozoic source rocks occur in the CGOM east of the Mississippi Delta. East of the delta, reservoir rocks in the CGOM range in age from Jurassic through Cretaceous. Reservoir rocks in the CGOM south of Louisiana consist primarily of sands ranging in age from Miocene through Pleistocene. The producing horizons grow progressively younger in age in a seaward direction. There are numerous structural and stratigraphic traps in the CGOM. Types of traps include anticlines and faulted anticlines formed by deepseated salt and shale ridges, salt and shale domes and salt massifs, and structural closure against normal and growth faults. Stratigraphic traps include sands onlapping salt and shale domes and anticlines, and facies changes from sands to impermeable shales in updip directions and at angular unconformities. In the portion of the CGOM east of the delta, prospective traps occurring in the Jurassic and Cretaceous updip sections where sand or porous carbonates pinch out or truncate updip, anticlinal structures developed on the down thrown sides of growth faults over deep seated salt domes and pillows, and very subtle fault closures.

3. Geohazards

The Southwest Louisiana Shelf and Slope, within the Pleistocene Trend, contains geologic features which must be considered as posing potential operational constraints to exploration and production activities. The following conditions pose potential operational constraints:

1. Shallow overpressured gas is widely distributed.

2. Buried stream channels are widespread and variable. Abrupt changes in bearing capacity of the channel fillings and gas prone sediments must be considered.

3. Many faults reach the surface or terminate just below it. Small escarpments and offsets of recent deposits indicate that gravity faulting and sediment adjustment is presently active.

4. Surficial slumping is most common around diapiric structures and on steeper slopes near the shelf edge. There are buried older slumps that can pose engineering problems. Slumping is more common on the continental slope.

5. Diapiric structures dominate the upper continental slope and are common on the shelf although usually more deeply buried. Numerous faults and fault scarps are associated with the structures, with some actually coming to the surface. The diapiric material is predominantly salt although shale diapirs occur. Movement may still be active on some of the diapirs at the shelf edge and beyond and could cause problems. The salt also appears to be moving horizontally toward the escarpment.

On the outer shelf and upper slope numerous salt diapirs with surface expression have living and dead reefal communities topping them.

The Mississippi/Alabama Shelf contains potential geohazards similar to the Louisiana Shelf.

1. Growth faulting extends from mid shelf to the foot of the continental slope between Horn Island and Pensacola.

2. Salt intrusions occur from DeSoto Canyon to the Mississippi Delta.

3. The Continental Slope is subject to sediment instability in the form of active mudflows, slumping, and erosional gullies.

The Mississippi Delta has a high potential for sediment instability. Rapid deposition of organic laden muds, silts, and sand tends to trap the evolving gasses which results in gas charged, underconsolidated, and by inference, unstable sediment masses. High river stages, large storms, sediment-degassing, fault movement and mud diapirism all can and do initiate downslope movement of great masses of sediment which continues to flow under the influence of gravity. There are also mud masses which flow at much lower rates for longer periods of time.

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G. Western Gulf of Mexico

The Western Gulf of Mexico planning area is situated primarily off the coast of Texas. The geologic features are similar to the Central Gulf, with known and potential hydrocarbon structures distributed throughout the area. Geologic and meteorologic conditions affecting operations are also similar to the Central Gulf.

The shoreline is principally barrier beaches backed by bays and wetlands. The shoreline is used extensively both for wildlife habitat, and recreation and tourism. However, there is also significant industrial use of the coastal area, especially in the vicinity of the Houston Ship Channel, and the oil and gas infrastructure is well developed.

The East and West Flower Garden Banks are examples of features of topographic relief along the Central and Western Gulf seafloor. Most provide substrate suitable for highly productive biological communities, but the Flower Gardens are unique in the northern Gulf of Mexico in consisting of living coral reefs. They support a population similar to that of Caribbean coral reefs. Special stipulations have been developed to protect the Flower Garden Banks and other similar resources, after several years of BLM-funded studies. These stipulations require monitoring and provide specifications for drilling field and cuttings disposal, as well as restricting the location of oil and gas operations in some cases.

Several endangered and threatened species occur in the Western Gulf planning area: critical habitat for the whooping crane; Attwater's prairie chicken; peregrine falcon; brown pelican; bald eagle; Eskimo curlew; American alligator; Houston toad; Kemp's ridley, green, leatherback, and loggerhead sea turtles; ocelet; and right, fin, and sperm whales.

1. Regional Geology

The Western Gulf of Mexico (WGOM) Planning Area includes the entire Texas shelf and slope including the deep water areas of Corpus Christi, Port Isabel, East Breaks, Alaminos Canyon, Garden Banks, and Keathley Canyon. This area is primarily an Early Cenozoic depocenter although Paleocene and Eocene strata are very deep. Sedimentation continued throughout the Cenozoic, but the sediment supply was far less than in the Central Gulf of Mexico (CGOM) Planning Area.

Structurally the WGOM has been subjected to essentially the same tectonic forces that shaped the CGOM. However, in contrast to the dominantly deltaic depositional environment of the CGOM, the WGOM is characterized by regional down-to-the-basin fault systems with rollover into the faults and linear sand reservoirs deposited in offshore bar facies. Masses of under-compacted shales have flowed into ridges, swells, and diapirs similar to the salt structures in the CGOM.

During the early Tertiary the primary supply of sediment to the Gulf of Mexico Basin came from the west down the ancestral Rio Grande and Brazos river systems. The potential for Paleocene strata occurring in the WGOM is very low because the main depositional area lies well inland from the WGOM. Onshore Eocene production comes mainly from low axial portions of embayments on the Texas Coastal plain. These sediments grade into bathyal sediments in the WGOM. Potential Eocene producing horizons are extremely deep and marginal. There is apparent production from Oligocene sediments in the WGOM at present. Studies indicate that Oligocene turbidites and deep sea fan deposits may be present in the shelf region and should be considered potentially productive. Miocene production occurs on the Texas shelf from the High Island Area to the North Padre Island Area. Lower Miocene sands in the WGOM consist mostly of regressive sands inter-fingering with marine shales and may be as much as 5,000 feet thick on the South Texas shelf. COST Wells Nos. 1 and 2 indicate that the Lower Miocene consists primarily of shale with thin sands in the area drilled. Several small deltas were formed in the Upper Miocene in the Rio Grande embayment. However, because of a narrow shelf favorable conditions for large accumulations of sand apparently did not exist. There is a perceived lack of good quality reservoir rocks in the Miocene in the southern part of the Texas shelf. Turbidity currents and submarine channels could have transported coarse and fine grained sediments

into deeper waters. There may exist, therefore, a Miocene potential in the deeper waters off South Texas. The Pliocene, in general, was subjected to the same type of depositional regime as the Miocene. Pliocene production occurs in the High Island portion of the WGOM but is less productive than off Louisiana because of a lesser sediment supply. The Pliocene has a maximum thickness of about 4,000 feet in the WGOM.

The Pleistocene sequence is exemplified by large quantities of sand deposited in a deltaic environment. Although punctuated by minor transgressions it was dominantly a regressive period. Production extends to the southern part of the Galveston area with significant accumulations of gas and condensate in the High Island area. Although the Pleistocene off South Texas attains a thickness of about 5,000 feet near the shelf edge, it remains nonproductive.

2. Petroleum Potential

Petroleum development in the WGOM has progressed in parallel with that in the CGOM though not as rapidly. There are approximately 150 producible fields in the WGOM, 90 of them are in the Galveston and High Island areas at the northern end of the WGOM. Production extends as far south as North Padre Island where there are five fields. Exploration and discovery have, in general, progressed from north to south and eastward into deeper water.

Source rock consists chiefly of organic-rich, Cenozoic shales. Studies indicate the possibility of Oligocene reservoir rocks in deeper waters. Miocene reservoirs extend the length of the WGOM in a narrow inshore band which widens to the northeast. There are Pleistocene reservoirs in the northern part of the WGOM. Trapping mechanisms are the same as those in the CGOM except that traps associated with rollover into growth faults are more prevalent and there is less salt diapirism. Numerous anticlinal shale ridges also provide structures for traps.

3. Geohazards

Recent sedimentation on the inner shelf has been occurring at a slow rate and sediments are normally mostly consolidated and stable. On the upper continental slope three areas containing older slumps have been located at the sites of the former Rio Grande, Colorado, and Brazos River deltas. The slumping was associated with lower stands of sea level. Shallow overpressured gas occurs at many locations in the Western Gulf. Diapirism is less prevalent toward the south but there are a few banks with drowned reefal communities located atop diapiric bulges extending south along mid shelf. Faulting tends to parallel bathymetry contours and must be taken into consideration locally.

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H. Southern California

The Southern California planning area extends northward from the United States-Mexico Provisional Maritime Boundary to the offshore extension of the county line between San Luis Obispo and Monterey Counties and surrounds six major nearshore islands. The Channel Islands off Santa Barbara form the seaward flank of the Santa Barbara Channel and Santa Catalina Island demarcates the San Pedro Channel. Promising oil and gas structures are located primarily in the Santa Barbara Channel, Santa Monica Bay, and San Pedro Bay. The continental shelf is very irregular off Southern California, with the slope occurring generally seaward of the islands, but extending out about 150 miles in the vicinity of Tanner and Cortes Banks.

Especially productive and diverse marine communities exist in connection with shallow banks, such as Tanner and Cortes Banks, as well as in the vicinity of upwelling and of converging water masses. The Santa Barbara Channel Ecological Preserve (3/21/69) and Channel Islands National Marine Sanctuary (10/2/80) were designated to protect and preserve habitat and wildlife. A special stipulation requiring biological surveys and imposing restrictions on drill cuttings and fluids disposal and structure placement has been used in these unique areas. The islands are important breeding sites for sea birds, seals, and other pinnipeds. A significant portion of the southern sea otter range is included in the planning area; the sea otter range also extends south of the northern planning area boundary. Whales migrate through the nearshore coastal waters. Commercial fishing efforts are concentrated in Morro Bay, in the Santa Barbara Channel, and further south in the vicinity of San Diego. A biological stipulation to provide special protection to biological resources has been applied in this planning area. Requirements for training of oil and gas personnel to reduce possible conflicts

with fisheries operations, and a well and pipeline stipulation to reduce obstacles to fishing gear have also been applied in this area.

The coastline of Southern California includes extensive beaches, as well as rocky shoreline. The coastal area is well developed, due to urbanization; Los Angeles to San Diego constitutes nearly a continuous urban corridor. Recreational use of Southern California's beaches and coastal facilities is extremely high. Also, extensive military activities are carried out in the Southern California planning area.

1. Regional Geology

The Southern California planning area has been divided into the outer basins and banks, the inner basins and banks, the Santa Barbara Channel, and the Santa Maria basin offshore. The inner and outer basins and banks areas are the offshore portion of the Peninsular Ranges Geomorphic Province. The Santa Barbara Channel is in the Transverse Ranges Province, and the Santa Maria offshore basin is part of the southern Coast Ranges Province.

The inner basins underlie the Santa Monica and San Pedro Bays which are offshore extensions of the Los Angeles basin, as well as the Santa Monica and San Pedro basins, the San Diego Trough, and the Gulf of Santa Catalina which is the offshore portion of the Capistrano Embayment. Of these, the Gulf of Santa Catalina and possibly the San Diego Trough and northern Santa Monica basin contain Paleogene and early Neogene sediments. The other basins and banks contain only middle and late Neogene sediments overlying metamorphic basement rocks. Structural features in the inner basins are primarily northwest-southeast-trending folds and faults.

The outer basins include the Velero, Long, East Cortes, West Cortes, Tanner, Patton, San Nicolas, Santa Cruz, San Clemente, and Catalina basins. Paleogene and Late Cretaceous sandstones and shales overlie metamorphic basement rocks on the Santa Rosa - Cortes Ridge and in the Velero, Long, East and West Cortes, San Nicolas, and Santa Cruz basins. These rocks are in turn overlain by Neogene sediments in the basins. Neogene sediments overlie basement rocks elsewhere on the outer basins and banks. Structural features are primarily folds and faults which trend northwest-southeast.

Sediments in the Santa Barbara Channel include a thick section of pre-Neogene marine and nonmarine conglomerates, sandstones and shales which are truncated to the west by an erosional unconformity. These older sediments are covered by Neogene sandstones, shales and fine-grained siliceous rocks which thicken toward the northeast. Structural features in the Santa Barbara Channel are faults and asymmetric folds which trend east-west.

Throughout much of the Santa Maria offshore basin, middle and late Neogene sediments overlie Cretaceous and older sediments and metamorphic rocks. Remnants of early Paleogene sediments have been preserved beneath the Neogene sediments in low areas around the periphery of the basin. Structural alignment of the folds and faults is generally northwest-southeast.

2. Petroleum Potential

The history of offshore exploration in the Southern California planning area can be divided into three phases. The first phase was carried out under leases from littoral landowners, and started in 1896 offshore of Summerland in

Santa Barbara County. The second phase began in 1921, with State legislation which permitted leasing of State tide and submerged lands, followed by further legislation in 1938, 1955, and 1957. Exploratory drilling on State tidelands as a consequence of this legislation resulted in the discovery of six fields prior to 1938 and twelve additional fields from 1943 to 1968. In addition, four fields have been discovered on tide and submerged lands granted to local governments. During this second phase many deep and shallow core holes were drilled offshore. The third phase began with the first Federal OCS oil and gas lease sale on the Pacific Coast which was held on May 14, 1963, and included tracts on the California OCS between Point Conception and the Oregon border. No discoveries were recorded from this sale. The first OCS lease sale of tracts south of Point Conception was held on December 15, 1966, and included one tract subject to State drainage in the Santa Barbara Channel. Since then eight lease sales have been held in the Southern California planning area.

Two COST wells were completed in 1975 and 1978 on of Cortes Ridge and west of Point Conception, respectively. As of December 1984, 273 exploratory wells have been completed.

The primary reservoirs in the Santa Monica and San Pedro Bays, and the northeastern Santa Barbara Channel are sandstone beds of middle and early Pliocene and late Miocene ages as is the case in their onshore counterparts, the Los Angeles and Ventura basins. Miocene sandstones and fractured fine-grained Monterey siliceous and calcareous reservoirs are the primary targets in most of the other inner and outer basins, in the southern and western Santa Barbara Channel and in the Santa Maria basin. Paleogene sandstone reservoirs are additional targets in the Channel and in the outer basins. While Miocene shales, especially the highly organic shales included in the Monterey Formation, are the major source rocks in Southern California, Pliocene and Paleogene shales may also be source rocks.

At the end of June 1984, remaining recoverable reserves of oil and gas on the southern California OCS were estimated to be 1,205 million barrels of oil and 2,198 billion cubic feet of gas. These reserves are contained in 23 fields, of which two are gas fields, thirteen are oil fields, and eight are combination oil and gas fields. At the end of 1984, seven OCS fields were on production, six in the Santa Barbara Channel and one in San Pedro Bay.

3. Geohazards

Potential geologic hazards that could inhibit the safe exploration and development of oil and gas resources on the southern California OCS include the high incidence of seismicity, active faults, mass transport of sediments, and steep slopes and canyon walls. Buried channels, hydrocarbon seeps, and shallow gas accumulations constitute less serious geologic constraints.

Southern California is a portion of the Pacific/North American plate boundary within the Circum-Pacific volcanic and seismic belt, which has been active throughout Cenozoic time and has been highly active in Quaternary time. The southern California OCS has a history of significant seismic activity.

Active faults are potentially hazardous because of possible ground rupture and shaking, and they may act as conduits for pressurized subsurface fluids to reach the surface. Inactive faults may be reactivated by injection or withdrawals on fluids. Active faults are present throughout offshore California. Active faulting and seismicity present a potential hazard for offshore operations.

Mass transport, the gravity-induced downslope movement of unconsolidated to semiconsolidated sediments, may cause loss of support for structures and pipelines. Such deposits are common along the northern slope of the Santa Barbara Channel and cover more than 90 percent of the central channel. They are also common on slopes in the inner and outer basins and banks. Four zones of mass transport deposits have been identified in the southern Santa Maria offshore basin. Due to the potential for loss of sea floor support of structures, the use of jack-up rigs in areas of mass transport zones is not prudent. However the substitue use of a semisubmersible or a drillship renders this hazard benign.

Slopes of greater than 10° are classified as steep. These slopes are common along the flanks of ridges and within submarine canyons of the Southern California planning area.

High-pressure shallow gas zones can cause blowouts if penetrated without proper drilling and casing procedures, and may also contribute to instability by lowering the shear strength of sediments. Shallow gas zones are confined almost exclusively to Pliocene and Pleistocene rocks along the shelf break at the northern edge of the Santa Barbara Channel, and along the coastal shelf from Palos Verdes to Mexico. Shallow gas is commonly associated with faulting and occurs along the flanks and crests of anticlinal structures throughout the Southern California planning area.

Abnormally pressured shallow gas zones are uncommon on the Pacific OCS due to the presence of unconsolidated to semiconsolidated near-surface sediments and their characteristic "bleeding off" of in situ biogenic gas. Most Pacific OCS shallow gas zones are at ambient pressures and do not pose a problem to drilling activities.

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I. Central California

The planning area extends from the offshore extension of the county line between San Luis Obispo and Monterey Counties to the offshore extension of the county line between Sonoma and Mendocino Counties. The continental shelf off the Central California planning area is narrow, extending out only about 30 miles. Geologic hazards include seismic activity, faulting, slope instability, and turbidity currents. Oceanographic hazards include occasional high sea states.

The Farallon Islands off San Francisco, surrounding banks, and other rocky banks are habitats of special concern. The Point Reyes-Farallon Islands National Marine Sanctuary was designated (1/16/81) "to protect and to preserve the marine birds and mammals, their habitats, and other material resources from those activities which pose significant threats." These areas, associated with the seaward edge of the continental shelf, provide substrate for a rich assemblage of attached organisms, which in turn attract fish. The Farallon Islands and other islands, as well as shoreline cliffs and offshore rocks, provide important breeding habitats for seabirds and marine mammals--seals, southern sea otters, etc. Whales migrate within sight of shore along the California coast. Special stipulations to protect biological resources and to require fisheries training for oil and gas personnel have been developed in the past for use in this area similar to those described for Southern California.

The rocky coastline, as well as ownership patterns, have limited industrial development along the coast. With the exception of San Francisco, only small ports exist which primarily serve fishermen.

1. Regional Geology

The Central California planning area includes the northern portion of the Santa Maria offshore basin, (sometimes referred to as the "Partington basin"), the Ano Nuevo (Outer Santa Cruz) basin, the La Honda (Inner Santa Cruz) basin, and the Bodega basin.

Available geologic evidence indicates that the present distribution of Paleogene and older sediments in the basins varies considerably throughout the planning area. In the Partington basin there is no evidence that Paleogene or older sediments are present, while in the Ano Nuevo basin to the northwest, early Neogene sediments and volcanics rest on Cretaceous rocks. Paleogene sandstones and shales are present in the La Honda basin onshore but late Paleogene sediments are absent due to Oligocene erosion in the Bodega basin which is the northwest extension of the La Honda basin.

In contrast to Paleogene sediments, Neogene sediments are widely distributed over the basin included in the planning area. In the Partington basin, the Monterey Formation apparently rests on basement rocks, while in the Ano Nuevo basin a thick section of Monterey rocks overlies early Neogene sediments and volcanics. Early to late Neogene sediments and volcanics are present throughout the La Honda and Bodega basins, however, late Miocene erosion removed much of the Monterey Formation in some portions of the Bodega basin. Organic rich, fine-grained calcareous and siliceous rocks of the Monterey Formation are present in

all the basins located within the planning area and under certain diagenetic conditions may provide the major source of hydrocarbons as well as become the primary reservoir in traps throughout the planning area. In the basins, rocks of the Monterey Formation are overlain by varying thicknesses of late Neogene mudstone, shale, and minor amounts of sandstone.

The planning area is in the offshore portion of the Coast Ranges Geomorphic Province and structural folds and faults trend northwest-southeast approximately parallel to the basin trends.

2. Petroleum Potential

The history of exploration in offshore Central California began with seismic surveys and dart sampling conducted in anticipation of the first Pacific OCS oil and gas lease sale which was held on May 14, 1963. Tracts were leased in the Ano Nuevo and Bodega basins, and while 12 exploratory wells were drilled on leased tracts, no discoveries were announced and all leases were relinquished by June 14, 1968. No other OCS sales have been held in the Central California planning area.

While the primary source and reservoir rocks in the four basins within the planning area are in the Monterey Formation of middle and late Miocene age, additional potential hydrocarbon sources and reservoirs exist in the shales and sandstones of the younger and older rocks of the sedimentary section. The basins are considered to be oil-prone.

The offshore Santa Maria basin may be the near character equivalent of the onshore Santa Maria basin. In onshore areas, petroleum has been produced primarily from fractured reservoirs in the fine-grained Monterey Formation, although there has also been some production from sandstone reservoirs. The onshore Santa Maria basin is one of the most productive oil bearing regions in California.

Some of the earliest oil and gas production in California (circa 1880), came from fields in the onshore portion of the La Honda basin, where oil ranging from 16°-45° API gravity was produced from Paleogene sediments as well as early and late Neogene sandstone reservoirs. Some of these oil-saturated sandstones are exposed in sea cliffs at Double Point (southeast of Point Reyes) and in onshore canyons northwest of Santa Cruz.

Ten wells were drilled in the Bodega basin and two in the Ano Nuevo basin on leases issued in the 1964 OCS lease sale. In both Ano Nuevo wells, drill cuttings throughout the nearly 3,000 feet of Monterey Formation were coated with free tarry oil, but no drillstem tests were run. Oil shows were encountered in six of the Bodega basin wells, one of which was tested, resulting in the recovery of only drilling mud and water.

3. Geohazards

Potential geologic hazards that could affect the safe exploration and development of oil and gas resources in the Central California planning area include a high incidence of seismicity, active faults, mass transport of sediments, and steep slopes and canyon walls. Buried channels, hydrocarbon seeps, and shallow

gas accumulations constitute less serious geologic constraints. The Central California planning area is located within the circum-Pacific volcanic and seismic belt, which has been active throughout middle and late Cenozoic time. Earthquakes of magnitude 5 and greater have been recorded from Monterey to San Francisco. Offshore basins in Central California lie adjacent to one or more seismically active faults and may be expected to experience seismically-induced ground motion. The San Andreas fault extends northwestward onshore in central California, intercepting the coast at San Francisco and Bodega Bay. The San Gregorio-Palo Colorado-Seal Cove fault zone along the Central California coast is considered potentially active.

Evidence of slope failure and the mass transport of surficial sediments is common on the continental slope west of Bodega basin and in the submarine canyons located in the planning area. Moderate (5-10°) to steep slopes (greater than 10°) occur along the continental slope off central California, on the flanks of the major bedrock highs rimming the basins, and locally within the many submarine canyon systems. Buried channels are also found in submarine canyon systems and fans.

In the Central California planning area, high pressure shallow gas zones occur in deformed sediments associated with fault zones and anticlines. Near-surface gaseous sediments at normal pressures occur in undeformed seaward-dipping unconsolidated to semi-consolidated sediments at the shelf break.

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J. Northern California

The Northern California planning area includes the area north of the previously described Central California planning area and extends northward to the Oregon border. It includes the two northernmost geologic basins off California: Point Arena and Eel River.

The continental shelf in the area is narrow, extending out only about 30 miles. Geologic hazards include seismic activity, faulting, slope instability, piercement structures and turbidity currents. Oceangraphic hazards include occasional high seas.

Shoreline cliffs and offshore rocks, provide an important breeding habitat for seabirds and marine mammals, namely seals. Whales migrate within sight of shore along the California coast. Habitats of special concern in the Northern California planning area include the Georges Reef near Crescent City and Tolo Bank south of the Mendocino Peninsula.

The rocky coastline, as well as ownership patterns, have limited industrial development along the coast.

1. Regional Geology

The Northern California planning area includes the Point Arena and Eel River offshore basins: These basins are separated by the Mendocino fracture zone.

The Point Arena basin is bounded on the east by the San Andreas fault, on the west by the Ocoonostota uplift, on the south by the Gualala uplift, and on the north by the Mendocino fracture zone. Although rocks of Paleogene age are present in the basin, the younger sediments have been removed by erosion during uplift in late Paleogene time. These older rocks are overlain by a thick section of Neogene rocks which ranges from earliest Miocene through Quaternary Age.

The Eel River basin offshore extends northward from the Mendocino Fracture Zone to Cape Blanco in southern Oregon. Sediments in the basin overlying metamorphic "Franciscan" basement rocks include rocks of Cretaceous and early Paleogene age which are separated from late Neogene age rocks of the "Wildcat Group" by a major unconformity. Gas is produced in the onshore Eel River basin from thin turbidite sandstone beds of Pliocene age.

The Northern California planning area is in the offshore portion of the Coast Ranges Geomorphic Province and structural folds and faults trend northwest-southeast to north-south, parallel to the alignment of the basin axes.

2. Petroleum Potential

To date, the only Pacific OCS oil and gas lease sale in the Northern California Planning Area was held on May 14, 1963, and included tracts in the Point Arena and Eel River basins. Four exploratory wells were drilled in the Eel River basin and three in the Point Arena basin on tracts leased in this sale. However, no discoveries were announced and all leases were relinquished. No OCS lease sales have been held in the Northern California planning area since then.

The primary source and reservoir rocks in the Point Arena basin are in the Monterey Formation of middle and late Miocene age. Additional potential hydrocarbon sources and reservoirs exist in the shales and sandstone above and below the Monterey Formation. Oil saturated sandstone beds in the Monterey Formation outcrop in the sea cliff at Arena Cove, and 29° API gravity oil was recovered in a wireline test of the Monterey Formation in an offshore well in which 90 percent of the drill cuttings were coated with free tarry oil.

Commercial gas is produced from thin Pliocene turbidite sandstone reservoirs in two fields in the onshore Eel River basin. Four dry exploratory wells were drilled along the edge of the basin offshore. Onshore, a minor amount (350 bbls) of high gravity (46° API) oil was produced from Cretaceous rocks near Petrolia, 10 miles south of the Eel River basin, and oil and gas seeps occur in Cretaceous and Pliocene sediments along the southern margin of the basin.

3. Geohazards

Potential geologic hazards that could affect the safe exploration and development of oil and gas resources in the Northern California planning area incude a high incidence of seismicity, active faults, mass transport of sediments, and steep slopes and canyon walls. Buried channels, hydrocarbon seeps, and shallow gas accumulations constitute less serious geologic constraints. Northern California is within the circum-Pacific volcanic and seismic belt that has been active throughout middle and late Cenozoic time.

The planning area is adjacent to seismically active faults and may be expected to experience seismically-induced ground motion. The San Andreas fault and the Mendocino fracture zone border the Point Arena basin on the east and north respectively, and the Mendocino fracture zone borders the Eel River basin on the south.

Evidence of slope failure and the mass transport of surficial sediments is common on the continental shelf and slope of northern California. Several large mass-transport deposits have been mapped in the offshore Eel River basin, and along the continental slope near Point Arena.

Moderate (5-10°) to steep slopes (greater than 10°) occur along the continental slope off northern California and on the Gorda Escarpment of the Mendocino fracture zone, as well as within the many submarine canyon systems located within the planning area. Buried channels also are found in submarine canyon systems and fans.

In the Northern Calfornia Planning Area, high pressure shallow gas accumulations occur in deformed sediments associated with fault zones and anticlines and in undeformed seaward-dipping unconsolidated to semi-consolidated sediments at the shelf break. Geopressured snales occur at depth in the offshore Eel River basin.

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K. Washington-Oregon

The Washington-Oregon planning area extends from the California-Oregon border to the U.S.-Canada border. The continental shelf is relatively narrow, ranging from 8 miles to 42 miles in width.

The Pacific Northwest coast is characterized by large inland bays and estuaries (e.g. Puget Sound and the Columbia River). These bays and estuaries are of considerable importance to the region's fish and wildlife resources serving as nursery and spawning areas for several important fisheries which include salmon, crabs, oysters, shrimp, and a few other fin fish. Offshore rocks, estuaries and extensive wetland areas also provide ideal habitats for a large and varied marine mammal and bird population.

The Washington and Oregon coastlines are primarily classified as undeveloped or designated for recreational use, with a few scattered small towns near bays and rivers. These coastal towns are primarily dependent on agriculture, fisheries, forest activities, or recreation. Commercial fishing is an important economic activity both regionally and nationally.

1. Regional Geology

The Washington-Oregon planning area includes the northernmost part of the Eel River basin and an elongate trough in which as much as 25,000 ft. of Tertiary sedimentary and volcanic rock has accumulated. This trough extends southward from Vancouver Island approximately 400 miles to the vicinity of the Klamath Mountains and from the base of the continental slope eastward to the western edge of the Cascade Range.

The three major Tertiary depositional cycles present in California are also present in the Washington-Oregon planning area. They include the Paleogene cycle comprising rocks of Oligocene and Eocene age, the early Neogene cycle consisting of rocks of early and middle Miocene age, and the late Neogene cycle made up of late Miocene and Pliocene rocks.

In the Eel River basin, which extends northward from offshore Cape Mendocino in California to offshore Cape Blanco in Oregon, the Paleogene cycle is deeply eroded and is overlain by late Neogene deposits, with early Neogene rocks missing. In the Coos Bay area north of Cape Blanco, early Neogene rocks are absent, but late Neogene rocks overlie a nearly complete Paleogene section. A similar condition exists offshore of Willapa, Washington. However, here the Paleogene section consists of a melange of Oligocene and Eocene sediments called the "Hoh Rocks" or "Hoh River Beds."

Throughout most of the trough, volcanic rocks of early Eocene age constitute economic basement. The only outcrops of early Neogene rocks north of the Mendocino Escarpment occur in Oregon near Newport and Astoria. These outcrops include the Astoria, Nye, and Yaquina Formations which are equivalent in age to the Monterey, Rincon, and Vaqueros Formations present in southern and central California. The rocks found in Oregon lack the high organic content of the rich source rocks of California. These formations are composed of sandstone, sandy siltstone, and mudstone beds. Many of the sandstone beds in the Washington-Oregon and Northern California planning area OCS are turbidites.

Snavely and others (1977) state that fold axes on the outer part of the continential shelf of Oregon and Washington trend roughly north-south, parallel to the base of the slope. On the inner shelf however, the trends of the folds vary from northwest to northeast. Some of the folds have highly deformed shale/siltstone cores. High-angle reverse faults are associated with the folding.

2. Petroleum Potential

A Washington-Oregon OCS lease sale was held on October 1, 1964. Offered in the sale were 149 tracts off the coast of Oregon and 47 tracts off the State of Washington. The sale resulted in the leasing of 74 tracts off the coast of Oregon and 27 tracts off the coast of Washington. On these leases, 8 exploratory wells (7 original holes and 1 redrill) were drilled off Oregon and 4 wells (3 original holes and 1 redrill) were drilled off Washington. All of the wells except one encountered abnormally high subsurface pressures while drilling. Indications of oil and gas were found in several of the wildcats, but none were considered to be commercial at the time. No OCS lease sales have been held in the Oregon-Washington planning area since the initial sale.

The siliceous rocks common in the Monterey Formation in California, which often are highly-fractured source and reservoir beds, are absent in the Washington-Oregon Planning Area. However, other potential source and reservoir rocks are present. The Nye Formation of Miocene age, the Alsea Formation of Oligocene age, and the Bastendorf Formation of late Eocene age contain organic shales of some richness.

Volcanic activity was prevalent in the area throughout much of Tertiary time. As a consequence, many of the sediments are tuffaceous. Tuffaceous rocks, in general, are poor reservoirs because they contain clay minerals which tend to fill the pore space, diminishing the effective porosity and permeability of the rocks.

At Coos Bay, the Coaledo Formation includes coal beds as well as sandstone beds from which non-commercial amounts of gas have been produced. The gas in the Mist field in northwestern Oregon is produced from Eocene sandstone

reservoirs and a minor amount of oil was produced from "Hoh Rocks" from 1957 to 1962 in the Ocean City oil field in southwestern Washington.

3. Geohazards

Most of the recently recorded major earthquakes in the Washington-Oregon planning area have been in Puget Sound. However, based on past experiences, major earthquakes can be expected for the entire planning area. The scarcity of geological and geophysical data make it impossible to completely assess the potential geologic hazards in the Washington-Oregon planning area. The following discussion is summarized from Snavely and others (1977). Potential geohazards that could affect the safe exploration and development of oil and gas resources in offshore Washington and Oregon include a high incidence of seismic activity and related seismically-induced geohazards; mass-transport of sediment; and sea-floor warping, subsurface overpressured zones, and shallow gas accumulations associated with diapiric intrusions.

The intense tectonic activity recorded in the Upper Cretaceous and Quaternary rocks and the earthquake history of the region indicate that the Washington-Oregon OCS continues to be seismically active. Seismically-induced geohazards include ground-shaking, fault displacement, ground rupture, tectonic warping and earthquake-induced mass-transport. Numerous faults that offset upper Pleistocene to recent deposits have been mapped in the coastal areas of Oregon and Washington.

Water-saturated or highly sheared Tertiary sedimentary rocks (Melange) and semi-consolidated Quaternary deposits which border much of the Washington coast are subject to loss of bearing strength or slope failure either under the influence of gravity or due to seismic groundshaking.

Areas of moderate to relatively steep slopes contain numerous slump features. These are most prevalent on steep slopes with thick sediment accumulations such as the continental shelf-slope break and on the flanks of submarine canyons that incise into the shelf. Interbeds of volcanic ash may be continuous for more than 18 miles offshore Washington and Oregon. These ash beds provide planes of weakness that may facilitate mass transport. The ash devitrifies readily in the marine environment which reduces the bearing strength of the sediments.

There are an estimated 50-100 diapiric intrusions on the Washington-Oregon OCS. These shale/siltstone piercement structures often warp and occasionally offset sea-floor sediments. The sediments included in the structures are probably overpressured and gas pockets may exist at shallow depths. Gas seeps are found along the flanks of the diapirs. Areas of unstable, poorly-consolidated deposits may exist along the flanks of the piercement structures.

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L. Gulf of Alaska

The Gulf of Alaska planning area includes part of a 900-mile long structural eature paralleling the southern Alaska coast which may be hydrocarbon productive. eohazards include active faulting, high seismicity, gas charged sediments, and ubmarine slides. While ice free year-round, icing of superstructures, and xtreme conditions, including wind and wave height, can present hazardous operating onditions.

The Gulf of Alaska coastal area is characterized by numerous bays and slands. Prince William Sound and the Copper River delta are major geographical eatures as well as highly biologically productive areas. Nearshore waters and ivers of the area are important nursery areas and spawning grounds for shrimp nd crab, and for salmon, respectively. The islands and other nearshore areas re extremely productive breeding grounds for seabirds and for marine mammals. arge seasonal concentrations of birds and mammals also depend on the area for oraging or migration staging. Seven endangered or threatened whale species and our bird species inhabit the area seasonally.

The coastline is virtually undeveloped, with only a handful of coastal owns or villages. However, the port of Valdez pipeline terminal is located ithin the planning area. The fishing industry is extremely productive in the ulf of Alaska, especially for crab, shrimp, salmon and a number of species of roundfish. Fishing is also important as a subsistence activity for the native opulation. Stipulations have been used in the Gulf of Alaska in the past to educe potential conflicts between oil and gas operations and commercial fishing nd subsistence activities. These have included a stipulation regarding design f wells and pipelines and a stipulation requiring environmental training for oil nd gas personnel.

1. Regional Geology

The stratigraphy of the Gulf of Alaska is dominated by four formations. he Mesozoic Yakutat Formation is believed to be the top of economic and acoustic asement in the Fairweather Grounds from Cross Sound to Dixon Entrance. Northeast f Cross Sound, the Yakutat Formation has a thick covering of Tertiary sediments. bove this formation is the middle Tertiary Kulthieth Formation which is seen in wo offshore wells. It has good reservoir and source rocks but wells have only eached it on the eastern and western flanks of the Bering Trough of the central ulf of Alaska. The late Eocene to early Miocene Poul Creek Formation above the ulthieth represents a fair source rock. It is seen both onshore and in five ffshore wells where it is a thick shale. The Upper Miocene to Pleistocene akataga Formation is predominantly glacially derived sediments which have mature source rocks and poor reservoir rocks. This is the dominant section hat was found by the ten unsuccessful wells drilled in the Bering Trough.

2. Petroleum Potential

Onshore oil and gas exploration began in 1902 from Kayak Island to ry Bay. Offshore exploration began in 1969 near Middleton Island and continued ntil 1982. Twelve exploration wells and one COST well were drilled with no iscovery of an oil or gas reservoir.

The only producing field along the Gulf of Alaska, Katalla, produced oil along a fault zone in the onshore Poul Creek Formation. Offshore these rocks are a massive shale and a potential source for petroleum but not a reservoir. In the five offshore wells that encounter the Poul Creek Formation, all have immature source rocks and the total organic carbon is less than one percent and usually 0.5 percent. The Kulthieth Formation may be a good reservoir and possibly another source for petroleum but this formation was only found in two offshore wells. The source rocks are more prone to have gas than oil. Most of the exploration wells have been drilled through the Yakataga Formation which is a very poor source rock and a fair reservoir rock.

The potential traps were mapped on the Yakataga and Kulthieth Formations. These traps are large anticlines which are asymmetric, elongate and doubly plunging, faulted anticlines and traps against major faults. Nine of these traps have been drilled with no discoveries of oil or gas.

3. Geohazards

Sea floor hazards in the Gulf of Alaska include faults, gas-charged sediments, submarine slides and buried channels. Surface and near-surface faults that show signs of recent activity occur in eight general areas: (1) Pamplona Ridge - Ice Bay zone, (2) Fairweather Ground shelf - edge structural high, (3) shelf-edge near Alsek Sea Valley, (4) seaward extension of the Fairweather-fault system, (5) south of Cape Yakataga, (6) on or adjacent to the Kayak Island platform, (7) on Tarr Bank, and (8) near Middleton Island.

Gas-charged sediments occur throughout the Gulf of Alaska generally covering small areas (less than 10 km^2). One exception is a nearshore area between the Dangerous and Alsek Rivers that encompasses over 200 km^2. Studies of the gas-charged sediment indicate that the source of the gas is the bacterial breakdown of organic material deposited in the rapidly accumulating Holocene sediment.

Submarine slides and slumps are prevalent on the walls of sea valleys, along the continental slope, and in nearshore zones, especially off the mouths of rivers. Sediment movement in the Gulf of Alaska can be triggered by gravity or earthquakes in areas with thick, unconsolidated sediment on moderate to steep slope angles. Most of the buried channels are concentrated in nearshore locations offshore of existing rivers and glaciers. The channels vary widely in size and most appear to have been cut into Pleistocene and older glacial sediment. Other hazards include tsunamis and seiches.

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M. Kodiak

This planning area is offshore Kodiak Island and includes the western central portion of the Gulf of Alaska. The Kodiak planning area contains the Kodiak Tertiary Basins. Geologic, weather and sea conditions are similar to the Gulf of Alaska. The area has a high potential for seismic events and volcanism, and contains shallow gas.

Kodiak Island, surrounding islands and Portlock and Albatross Banks host some of the Gulf of Alaska's greatest concentrations of bird and sea mammal nesting sites, foraging areas, and shellfish nursery areas. Seven endangered whale species and four bird species inhabit the area seasonally. The western portion of the Gulf of Alaska supports a large part of the Gulf fishery. Kodiak's port services the Gulf commercial fishery--Kodiak has been among the top 10 fishing ports (for pounds landed) in the U.S. in the last 10 years. The island is also seeking to expand its fish processing industry especially for bottom fish species.

1. Regional Geology

The tectonic setting of the Kodiak shelf is within an arc-trench gap which separates the active Alaska-Aleutian magmatic arc on the northwest from the Aleutian trench to the southeast. Since early Cenozoic time, Pacific plate lithosphere has migrated northward relative to mainland Alaska and the North American continent. This differential movement is accommodated at the Aleutian trench where Pacific lithosphere is subducted beneath the Alaskan continental margin. The tectonostratigraphic evolution of the Kodiak shelf fore-arc basin has been strongly controlled by the nature and episodicity of interaction between the two major crustal plates at this zone convergence.

The Kodiak shelf is underlain by two major tectonostratigraphic units. Acoustic basement beneath the shelf is composed of a highly deformed assemblage of flysch and mafic volcanic rocks ranging in age from Paleocene or older to Oligocene. This basement complex is unconformably overlain by up to 25,000 feet of gently-deformed shelf sediments ranging in age from Miocene to Recent. Available seismic data is only capable of resolving coherent, mappable reflectors within or at the base of the younger shelf sequence.

2. Petroleum Potential

Source rock potential for most rocks underlying Kodiak shelf is poor. Most strata contain less than 0.5 percent total organic carbon (TOC) rendering them marginal potential sources at best. Data from the Middleton Island well, 200 km along strike to the northwest, suggest that isolated source beds may be present in strata scattered throughout the Tertiary section that contain sufficient organic carbon to make them good potential source beds. Structured

Kerogen predominates in these source beds which, due to the low H/C ratio, indicates that these rocks would tend to generate gas rather than oil. Significant exceptions to this pattern are Eocene beds that contain primarily amorphous Kerogen. These beds, which have an aggregate thickness of 385 feet, could generate oil rather than gas. Thermal maturity for rocks underlying Kodiak shelf is low. Beneath Kodiak shelf, oil generation, if present is in the early generation stage and thermogenic gas generation has not yet commenced.

Folds and faults which deform the shelf sequence trend predominately northeast parallel to the axis of the Aleutian trench. These structures are superimposed on larger-scale transverse uplifts which strike orthogonal to the main arc trend and segment the shelf into discrete, equidimensional basins. Recognized hydrocarbon traps underlying the Kodiak shelf are simple structures limited to Neogene strata and are found throughout the Kodiak shelf. Trap types include simple folds, fault closures, and unconformity truncations. No regional seals are known to be present but interbedded shales which enclose reservoir sands and which are capable of acting as local seals may be reasonably presumed to be present in all structures.

Reservoir rocks are unlikely to be present in Paleogene strata due to both their original lithology and subsequent degree of alteration. However, some reservoir rocks with reservoir-quality porosity and permeability are inferred to be present in Neogene strata. Samples obtained from the Paleocene Ghost Rocks Formation and the Eocene and Oligocene Sitkalidak Formation have both low porosity and low permeability (1-3 percent and less than 0.1 millidarcy, respectively). Direct measurements of the porosity and permeability of Miocene and younger sandstones exposed onshore are not available, although thin Pliocene sands in the Middleton well range up to 18 percent in porosity. Lithologic descriptions of outcrops on Kodiak and surrounding islands reveal that in general, sediment tends to increase in compositional maturity and porosity and permeability with decreasing age throughout the sampled part of the Neogene.

3. Geohazards

Geological aspects of the Kodiak shelf which pose potential hazards to petroleum-related activities include large-magnitude seismic events, active faults, mobile seafloor sediment, shallow gas accumulations, and volcanic activity. Shallow faults and gasification of near-surface sediments offer potential problems to both exploration drilling and production operations. The remaining geohazards are episodic and chiefly impact long-term operations such as production development. Other hazards include superstructure icing, tsunamis, and seiches.

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N. Shumagin

This planning area is situated south of the Alaskan Peninsula and Unimak Island. It includes two basins identified as possibly containing hydrocarbons--the Shumagin Basin, between Semidi and Shumagin Islands, and the Sanak Basin, northeast of the Sanak Islands. Geohazards include faulting, volcanism and earthquakes.

The south side of the Alaska Peninsula is characterized by rocky cliffs and beaches and is virtually undeveloped. Human use of the coastal area is confined to subsistence uses. Offshore, the primary human use is commercial fisheries. Additionally, the coastal waters of this area are important for producing shrimp, crab, and bottom fish species.

As in the Kodiak vicinity, the islands in the Shumagin planning area also support high concentrations of nesting bird colonies and pinniped habitat.

1. Regional Geology

The tectonic setting of the Shumagin Shelf is within an arc-trench gap which separates the active Alaskan Aleutian magmatic arc on the northwest from the Aleutian trench to the southeast. Since early Cenozoic time, the Pacific plate lithosphere has migrated northward relative to mainland Alaska and the North American Continent. This differential movement has been accommodated at the Aleutian trench where Pacific lithosphere is subducted beneath the Alaskan continental margin. The techtonostratigraphic evolution of the Shumagin Forearc Basins has been strongly controlled by the interaction of these two major crustal plates at this zone of convergence.

The Alaskan Peninsula northwest of the Shumagin Shelf contains a Mesozoic sequence of volcanoclastic sandstone and siltstone, in addition to a sequence of arkosic sandstone and conglomerates. Tertiary sedimentary rocks contain a high percentage of andesitic and basaltic rock fragments.

Southeast of the shelf-type Mesozoic sequence of the Alaskan Peninsula, is the Shumagin Formation of Late Cretaceous age found on Sanak and the outer Shumagim Islands. The islands are an uplifed portion of the Shumagin shelf which exposes an ancient deep water flysch sequence of interbedded sandstone and mudstone which has been intruded by granitic plutons.

Geophysical data accumulated and tied into the adjacent geologic and geophysical interpretation of the Kodiak Shelf indicate two major tectonostratigraphic units which underlie the Shumagin Shelf. Acoustic basement consists of highly deformed and disrupted sedimentary sequence ranging in age from Paleocene or older to Oligocene. Filling of the basins which rest upon acoustic basement is up to 25,000 feet of gently deformed shelf and upper slope sediments ranging in age from Miocene to recent.

Folds and faults which deform the sequence of sediments on the shelf predominantly follow the axis of the Aleutian trench. The rocks of the Kenai Peninsula, the Kodiak Islands, and the Shumagin Islands generally strike northeast, while rocks on the Sanak Islands strike northwest toward Unimak Island and the margin of the Bering Sea Shelf beyond.

2. Petroleum Potential

The Shumagin planning area is a frontier region without well data. The closest oil and gas fields are located within Cook Inlet, approximately 700 km to the northeast.

Preliminary observations of geophysical data indicate that both structural and stratigraphic traps located offshore appear capable of entrapping hydrocarbons. Verification of closure, in most cases, has been tentative, due to the low density of the geophysical data.

Structures are considered most prospective where broad anticlinal folds and stratigraphic terminations flank basins within which adequate levels of thermal maturation have been reached for generation and expulsion of hydrocarbons. To date there has been no geologic data on the Shumagin Shelf to verify the reliability of either a sufficient source or presence of a porous reservoir sequence. Geologic analysis of potential liquid hydrocarbon sources and potential reservoirs from the adjacent Kodiak Shelf suggest a low to moderate probability for the occurrence of commercial accumulations within the Shumagin Planning Area.

3. Geohazards

High resolution data shot on the Shumagin Shelf by the USGS has not been interpreted at present. The Shumagin Shelf, located within the same tectonic belt as the Kodiak Shelf, probably contains similar petroleum engineering constraints. The Kodiak Shelf is associated with large magnitude seismic events, active faults, mobile seafloor sediment, shallow gas accumulations, and volcanic activity. When the Shumagin gap ruptures, the energy release could range as high as 9 Richter magnitude and produce a broad spectrum of frequencies. Other hazards include tsunamis and seiches.

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0. Cook Inlet

The Cook Inlet Planning area extends from the State of Alaska waters to southwest Shelikof Straits. In addition to the seismic risk common to southern Alaskan

planning areas, Cook Inlet experiences swift tidal currents and ice floes for about 4 months of the year. Geohazards are principally scour and fill, sediment slumping, volcanism and strong motion earthquakes.

The Inlet is a tidal estuary and is bordered mostly by beaches and tidal flats, with some rocky shores. It is an important area of waterfowl and shorebird nesting, especially Kachemak Bay. Shrimp, salmon and crab are commercially fished. The area also supports a good sports fishery. Three endangered whale species inhabit the area.

Anchorage is situated at the northern end of Cook Inlet and is the financial, population and service center of Alaska. The Kenai Peninsula is also relatively well populated, and supports a modest oil and gas industry, including infrastructure for offshore development. In past lease sales, stipulations similar to those described for the Gulf of Alaska have provided for protection of fishing activities.

1. Regional Geology

Rocks of lower Cook Inlet are part of a belt of Mesozoic and Cenozoic sedimentary rocks that underlie upper Cook Inlet on the northeast and the Alaska Peninsula and the Shelikof Strait on the southwest. Locally along this belt, marine Mesozoic rocks may be more than 11,000 m thick, and continental Cenozoic rocks are as much as 7,600 m thick. Four major northeast-trending geologic features that flank Cook Inlet are the Alaska-Aleutian Range batholith and the Bruin Bay fault on the northwest side, and the Border Ranges fault and the terrane of undifferentiated Mesozoic and Cenozoic rocks on the southeast side.

2. Petroleum Potential

One COST well and 13 exploratory wells have been completed to date. Commercial oil and gas fields are located both onshore and offshore in upper Cook Inlet north of Kalgin Island. No commercial discoveries have been made in the planning area. Two Federal lease sales, Sale CI and 60, have been held in the lower Cook Inlet/Shelikof area. Eight exploration wells (as of November 1984) have been drilled in the Sale CI area. Two of these wells had significant oil shows but both wells were tested as being non-commercial. These wells tested many of the major structures in lower Cook Inlet. All of the leases from Sale CI have expired and there are thirteen active leases (as of November 1984) from Sale 60.

Generalized lithologic characteristics have been compiled from the eight exploration wells and the Continental Offshore Stratigraphic Test well drilled in lower Cook Inlet. These characteristics were used in evaluating the four ages of rocks; Jurassic, Early Cretaceous, Late Cretaceous, and Tertiary for their potential for reservoirs.

The Jurassic rocks are only partially penetrated in nearly all the wells to as much as 12,000 feet. This section is very sandy but it has uniformally low porosity and permeability due to cementation. These rocks have poor reservoir potential.

The Early Cretaceous rocks range in thickness from 0 to 2,500 feet. Although this interval has numerous sands, the sands have low porosities and permeabilities. The reservoir potential for the Early Cretaceous is considered to be poor.

Rocks in the Late Cretaceous are both marine and non-marine. The marine section has from 1,000 to 5,000 feet of siltstone. These rocks have very few sands and the sands have low porosity. In contrast, the non-marine rocks are sandier, have marginal porosities, and two wells to the north encountered non-commercial quantities of oil. The marine rocks are considered to have poor reservoir potential while the non-marine rocks have good reservoir potential. The non-marine section has only been found in the west central part of Cook Inlet.

The Tertiary rocks are Eocene to Paleocene in age. These rocks are from 500 to 1,000 feet thick and their lithology changes from tuffaceous siltstone to a massive conglomerate. This section has low porosity and has very poor reservoir potential.

The petroleum potential for the planning area is considered low. Ten of the best prospects in the area have been drilled with non-commercial oil shows being present in only two. All wells showed the marked lack of good reservoir rock.

3. Geohazards

Seismicity, vigorous sea floor erosion, volcanic activity, shallow gas accumulations, and active faults all pose potential hazards to hydrocarbon exploration and production. Local seismic events, commonly ranging from 3 to 6 Richter magnitude, are characterized by high-frequency vibrations whose potential for damage is highest for rigid, non-reinforced structures, e.g., ladders and piers. The low frequencies, the most damaging, pose a serious threat to large structures such as production development equipment. Shallow faults and gasification of near surface sediment pose a threat to both exploration and production operations. Other hazards include tsunamis and seiches.

Catastrophic eruption of one of the Aleutian Range volcanoes is a possibility and could result in a major ashfall throughout the planning area.

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P. North Aleutian Basin

North Aleutian Basin is bordered by mainland Alaska to the northeast and the Alaskan Peninsula and Unimak Island to the south-southwest. The primary geologic feature which is thought to be hydrocarbon productive is an inner-shelf basin situated along the southern end of the Alaskan Peninsula.

The area is prone to seismic events and volcanoes. It is also subject to occasionally strong wind and wave conditions and ice in severe winters.

Bristol Bay is extremely productive and supports a very valuable crab and bottom fishing industry, as well as one of the world's largest salmon fisheries. The salmon migrate along the Alaskan Peninsula.

Izembek Lagoon, at the southern edge of the Alaskan Peninsula, is an extremely important feeding and staging area for migratory birds. This area also supports eel grass beds which are among the most productive in the world. As with other southern Alaskan areas, this planning area is also highly productive for marine mammals; it also serves as a migratory pathway for whales. Eight endangered whale species and four endangered bird species inhabit the area seasonally.

Subsistence use of the coastal area, including coastal salmon fisheries, is high.

1. Regional Geology

The North Aleutian Basin planning area lies north of the Alaska Peninsula and east of longitude 165° west. Measuring approximately 475 x 200 miles, the basin encompasses about 95,000 square miles. From the northwest, basement rocks gradually deepen to the basin axis but rise abruptly to the southeast of the axis to the northwest-facing foothills of the Alaska Peninsula.

Three geologic trends lie within the planning area. The North Aleutian Basin proper lies north of latitude 55° 45' and is oriented approximately east-west. On its southern boundary is the Black Hills uplift, which trends westward from Cape Leontevich. To the south of the uplift lies the Amak Basin. The large graben in St. George's Basin extends a few dozen miles into the west central portion of the planning area.

Sedimentary fill of the basin consists of up to 20,000 feet of Cenozoic sediments, thickest in the southeast part of the basin. Major Paleogene formations exposed onshore include, in order of decreasing depth, Tolstoi, Meshik, and Stepovak. The Tolstoi and Meshik Formations are largely volcanic conglomerate, sandstone, and breccia with some interbedded siltstones. The Stepovak has, in addition to volcanic sandstones and conglomerate, thick beds of black siltstone; and there are lignite seams in the upper part of the sequence. All three formations are dense and highly indurated. In the Neogene, the Bear Lake and Milky River are the two prominent formations. The former is porous sandstone and conglomerate with interbedded siltstone; the latter, lying above it, is conglomerate, sandstone, and mudstone. The Neogene formations and overlying Pleistocene volcanic flows and breccias were deposited in shallow-marine and non-marine environments. Seismic data strongly suggests that these same formations continue offshore, and dip to greater depths there.

2. Petroleum Potential

Nine wells were drilled on the Alaska Peninsula adjacent to the axis of Bristol Bay. Although a number of oil and gas shows were reported, none suggest a discovery of commercial size. One COST well has been drilled. Data from the onshore wells suggests that the most prospective area for hydrocarbons lies offshore from Port Moller to Amak Island. Later geophysical work shows that this area contains both the thickest Tertiary section and also the most promising anticlinal structures.

In addition to those, there are less promising structures in the southwest corner of the basin and to the north of Port Heiden. There may also be stratigraphic or fault traps along the south flank of the Black Hills uplift.

The Gulf Sandy River and Pan American David River wells suggest that the Middle to Late Miocene sandstones of the Bear Lake Formation have the greatest reservoir potential. Above 6,300 feet, these sandstones have porosities as high as 36.5 percent and permeabilities as high as 1,286 millidarcies (mD). Below 6,300 feet, the corresponding high values are 29 percent and 43 mD. Shows of oil and gas have been reported from the Bear Lake sandstones in both wells, and may possibly occur offshore also.

The best Tertiary source rocks appear to be the black marine siltstone and shale beds in the Oligocene-age Stepovak Formation. Analysis of several wells onshore shows the Paleogene strata are rich in organic matter but thermally immature. Offshore, however, these rocks should be more mature owing to the greater depth of burial. Other potential source rocks include the basal units of the Bear Lake (where buried deeply) and marine shales of Late Jurassic and Late Cretaceous age (if in angular discordance with overlying reservoir rocks).

3. Geohazards

Seismicity, vigorous sea floor erosion, volcanic activity, shallow gas accumulations, and active faults all pose potential hazards to hydrocarbon exploration and production. Local seismic events, commonly ranging from 3 to 6 Richter magnitude, are characterized by high-frequency vibrations whose potential for damage is highest for rigid, non-reinforced structures, e.g., ladders and piers. When the Shumagin gap ruptures, the energy release could range as high as 9 Richter magnitude and produce a broad spectrum of frequencies.

The low frequencies, the most damaging, pose a serious threat to large structures such as production development equipment. Shallow faults and gasification of near surface sediment also pose a threat to both exploration and production operations. Other hazards include tsunamis.

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Q. St. George Basin

St. George has similar types of geologic prospects as North Aleutian Basin, with possible hydrocarbon structures extending seaward (northwest) from Unimak Pass. It shares similar geologic and meteorologic hazards. There is potential for severe storm conditions, high waves, seismic events, sediment mass movement, gas charged sediments, and local erosion.

One of the unique features of the planning area is Unimak Pass, through which whales and other cetaceans and fur seals migrate. The Pribilof Islands also represent a unique resource, seasonally supporting millions of nesting sea birds and most of the world's population for northern fur seals. High concentrations and large numbers of other pinnipeds also inhabit the Pribilofs and the Aleutian Chain.

Subsistence use of the Aleutian Chain and Pribilof Islands is high; in addition, Unalaska/Dutch Harbor and Cold Bay serve as transportation centers and support centers for the fishing industry and the entire region.

1. Regional Geology

Two major depocenters for Tertiary sediments occur on the continental shelf in the planning area: the St. George graben and the Pribilof Basin. The St. George graben is 10 to 25 miles wide, extends approximately 200 miles in a northwest/southeast trend, and contains as much as 40,000 feet of Tertiary sediments. The Pribilof Basin is a half graben that is 30 miles wide, extends approximately 70 miles in a northwest/southeast trend, and contains as much as 20,000 feet of Tertiary sediments. The shelf area south of the graben to the continental slope contains as much as 10,000 feet of Tertiary sediment over mostly sedimentary Mesozoic rocks. The area up to within 25 miles north of the graben contains 3,000 to 7,000 feet of Tertiary sediment over igneous Mesozoic rock. The remainder of the shelf area has a very thin Tertiary section over igneous basement and is not considered prospective.

COST No. 1 well was drilled about 25 miles south of the graben and encountered about 10,000 feet of Tertiary sediments overlying the igneous rock basement. COST No. 2 well was drilled along the southeastern margin of the graben and encountered over 12,000 feet of Tertiary sediments overlying Mesozoic sedimentary rocks. The Mesozoic rocks ranged in age from Late Jurassic to Early Cretaceous and were mostly fine-grained sandstones with minor shale and coal stringers. They were derived from a volcanic source terrane and deposited in a fluvial to deltaic environment. The Tertiary sediments ranged in age from Middle Eocene to Recent. Dominant lithologies included fine-grained sandstones, siltstones, mudstones, and minor conglomerate. Volcanic rock fragments were common throughout. The sediments were deposited in mostly a marine shelf environment.

2. Petroleum Potential

The basin is in the early stage of exploratory drilling. Two COST wells and nine exploratory wells have been completed as of September 1, 1985.

Potential traps in the graben include faulted anticlines, upthrown fault traps over basement horst blocks, downthrown fault traps along border faults of the graben, drape of tertiary strata over basement fault blocks, stratigraphic onlap of Tertiary sediments onto the basement, and possible stratigraphic pinchout of sands. Outside of the graben, potential traps include sub-unconformity truncation below the Cenozoic-Mesozoic unconformity, anticlinal structures within the Mesozoic section, drape of Tertiary strata over Mesozoic highs, fault-bounded traps, and stratigraphic onlap of Tertiary sediments onto Mesozoic highs. In the Pribilof Basin, potential traps include anticlines within the Mesozoic section with drape in the overlying Tertiary section, upthrown fault traps over tilted basement blocks, and sub-unconformity truncation associated with fault-bounded anticlines.

The best potential reservoir rocks are believed to occur in the Oligocene section. At COST No. 1 Well, Oligocene sands attained thicknesses greater than 150 feet. Porosities were as high as 25 percent and permeabilities were as high as 37 millidracies. The volcanic rock fragments tend to reduce porosity and permeability because of diageretic alteration to zeolites and clay minerals. The Mesozoic sandstones at COST No. 2 Well were very tight.

The source rock potential as indicated by the COST wells appears to be low. The sediments were low in total organic carbon and were deposited under oxidizing conditions. Only gas-prone kerogen types were present in samples from the wells. The geothermal gradient is approximately 1.5° F/100 feet. Vitrinite reflectance data indicated the Tertiary sediments to be immature for oil generation. The "oil window" occurs at approximately the base of the Tertiary section.

The deeper portions of the St. George graben may have better source rock potential than the COST well sites, because the basal graben sediments were deposited in an enclosed basin when the area south of the graben, where the COST wells were drilled, was emergent. Restricted circulation in the early stage of graben development may have been conducive to organic preservation. Thermal maturity in the graben may also be more favorable than for the COST well locations. This is because the basal graben sediments are buried more deeply than the lowermost Tertiary sediments at the COST well sites, and therefore, may have been exposed to high enough temperatures for a sufficiently long time to generate oil. The basal Tertiary section in the Pribilof Basin may also contain favorable source rocks.

3. Geohazards

Potential geologic hazards in the planning area include shallow gas, shallow faults, seismicity, volcanism, and unstable slopes. Other environmental constraints are associated with the harsh climate, such as pack ice, superstructure icing, and storm waves. Tsunamis and seiches are other hazards.

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R. Navarin Basin

Navarin Basin is closer to the Russian mainland (about 90 miles) than it is to the Alaskan mainland. The eastern boundary of the planning area is about 30 miles west of St. Matthew Island, about 180 miles from the larger island of Nunivak and over 200 miles from the mainland. A large northwest/southeast trending basin is situated along the center of the planning area which may be hydrocarbon productive. Faulting, gas charged sediments, and sea floor slumping are the major geohazards.

While weather conditions are generally similar to other Bering Sea areas, this area is annually covered with ice, and the area is subject to high wave conditions, storm currents, and ice-wave coupling.

The region supports a large bottom fishery which, at this time, is predominantly foreign. East of the planning area, St. Matthew and Nunivak Island, are important waterfowl and shorebird areas (they are wildlife refuges). The entire Kuskokwim-Yukon delta which is shoreward, but over 200 miles from the planning area is also an important waterfowl and shorebird area. Six endangered whale species and two endangered bird species inhabit the area seasonally.

1. Regional Geology

The Navarin Basin consists of three en echelon subbasins filled with more than 26,000 feet of layered Tertiary sedimentary rock. The subbasins formed as a result of extensional deformation associated with strike-slip motion or oblique subduction of the Kula Plate beneath the North American Plate in the Late Cretaceous to early Tertiary time. Basin axes trend northwestward and parallel the continental shelf break. By the late Eocene, movement of the Kula Plate was isolated by subduction at the Aleutian Arc. Subbasin subsidence in response to structural downdropping remained active until the late Oligocene. This allowed the continuous deposition of marine mudstones and siltstones throughout most of the Paleogene. Sea level lowerings in the "middle" and late Oligocene,

however, exposed older Tertiary and Mesozoic basement highs to wave-based erosion, which resulted in the deposition of coarser grained material along the subbasins flanks. Cessation of Kula Plate subduction by the late Eocene was followed by crustal cooling which allowed regional subsidence beyond structurally defined subbasins. Middle and outer neritic mudstones and sandy mudstones were deposited throughout the Neogene, with a possibility of coarser grained deposits flanking basement highs that were exposed to wave-base erosion during a sea level lowering in the late Miocene.

2. Petroleum Potential

ARCO Alaska, Inc., drilled a Continental Offshore Stratigraphic Test (COST) well in the summer of 1983. Stratigraphic test well data indicate the late Eocene and early Oligocene mudstones to be the most favorable source rocks in the Navarin Basin. This stratigraphic sequence thickens in the deeper parts of the subbasins, thus possibly providing significant amounts of oil-prone rocks at a favorable level of thermal maturity. Possible reservoir rocks are Oligocene sandy mudstones, basal sands deposited by the early Tertiary transgression over the Mesozoic basement rocks, and coarse grained deposits flanking basement highs that were deposited during sea level lowerings in the Oligocene and Miocene. Traps found in the basin include anticlines, faulted anticlines, fault traps, and stratigraphic pinchouts. Many trap are adjacent to the potential source rocks, however, traps that are not adjacent may be fed by hydrocarbon migration along unconformities, faults, and through permeable strata.

As of September 1, 1985, 3 exploratory wells have been completed. There are no known hydrocarbon accumulations in the Navarin Basin or other Tertiary basins in the Bering Sea. The major problem facing hydrocarbon production in the Navarin Basin will be finding significant amounts of reservoir rocks.

3. Geohazards

Sea-floor instability, gas-charged sediments, and possible overpressuring are major geologic hazards in this basin. Sea-floor instability hazards which may affect bottom-founded structure include faulting, seismicity, slides, and erosion. Shallow gas-charged sediments may result in unstable foundation conditions. Investigations of surface samples indicate that most shallow gas is biogenic in origin, however, thermogenic gas may be present. Unpredicted abnormal hydrostatic pressures can be hazardous during drilling. Abnormal pressures were encountered in the Tertiary rocks during the drilling of the stratigraphic test well. Basin characteristics such as shale diapirs, gas-charged sediments, and a thick, rapid accumulation of fine grained material indicate that overpressuring may be prevalent in the basin. Other hazards are sea ice, and superstructure icing.

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5. Norton Basin

Norton Basin planning area is situated along the southern portion of the Bering Strait and includes Norton Sound and St. Lawrence Island; the Yukon River delta forms the southeastern landward boundary of the planning area. A large, inner-shelf basin situated generally in the center of the planning area may contain hydrocarbons. Geohazards of this area include shallow gas, buried peat layers, and ice-gouged sediment, faults and earthquakes.

The weather in this planning area is severe much of the year and there is ice cover during the winter months in all years.

The shoreline throughout much of the area consists of beaches, cliffs, barrier spits and islands, and tidal flats, except for the Yukon River delta in the south. This delta area, as well as St. Lawrence Island, hosts extremely high numbers of nesting waterfowl and seabirds, respectively.

The Bering Strait is used as a migratory passage for the bowhead and beluga whales, walrus and other marine mammals, as well as migratory birds. Six endangered whale species and three bird species inhabit the area seasonally.

Coastal uses include subsistence hunting and fishing. There are small commercial fisheries for herring and crab in the sound. Nome is situated along the northern landward boundary of the planning area. It is a transportation and commercial center for northwestern Alaska. Historically, Nome has been a mining center as well.

1. Regional Geology

Norton Basin consists of two subbasins filled with more than 14,000 feet of layered Tertiary sedimentary rocks. The Basin formed as a result of pull- apart tectonics associated with Late Cretaceous or early Tertiary strike-slip motion along the Kaltag fault. Apparently the two subbasins were not formed

until the mid-Eocene when the north-trending Yukon horst developed as a common boundary. Continental sedimentation dominated Norton Basin prior to the mid-Eocene. Until the mid-Oligocene the horst allowed the shallower marine siltstone and sandstone sequence to be deposited in the eastern subbasin, whereas deepwater clastics were deposited in the western subbasin. Post mid-Oligocene deposition extended beyond the controlled subbasins indicating regional subsidence in response to crustal cooling. This extension unified deposition from late Oligocene to present within the two subbasins. This sequence of rock is mainly Oligocene coals and Neogene shallow-marine siltstones, sandstones, and diatomaceous mudstones. The Oligocene consists mainly of mudstones, siltsones and sandstones with well over half of the sediments coal-bearing.

2. Petroleum Potential

ARCO Alaska, Inc., drilled two COST wells in the planning area during the summers of 1980 and 1982. Post-Sale 57 activity included 6 exploratory wells drilled as of September 1, 1985.

Stratigraphic test well data indicated the most common organic material present is Type III humic kerogen. Sufficient maturity for oil generation exists below 9,500 feet in the western subbasin and 10,600 feet in the eastern subbasin. The area is considered gas prone. Below 13,000 feet there is insufficient organic carbon to serve as a commercial hydrocarbon source. Sandstone porosities of greater than 13 percent and permeabilities of 1 millidarcy are restricted to depths less than 9,000 feet (mid-Oligocene or younger) in the eastern subbasin. Sandstone with porosities of greater than 24 percent and permeabilities of 1 millidarcy are restricted to depths less than 6,000 feet (late Oligocene or younger) in the western subbasin.

Anticlines, faulted anticlines, fault traps, and stratigraphic pinchouts are present in the Norton Basin. Faults and unconformities are present to provide migration routes. The major problem facing Norton Basin hydrocarbon production is having a sufficient amount of source rocks with the proper kerogen. There are no known oil and gas fields within Norton Basin or similar Tertiary basins in the Bering Sea continental shelf.

3. Geohazards

Sea-floor instability in the form of ice-gouging, current erosion, seismicity and gas-charged sediments may be hazardous to bottom founded structures. Gas-charged sediments are most likely biogenic in origin, however, thermogenic gas accumulation is present at one known site. Geohazards also include coastal erosion, liquification of seafloor sediments, and current scouring of sediments. Other hazards may consist of sea ice, storm surges, migratory shoals, superstructure icing, and over ice flooding.

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T. Hope Basin

Hope Basin is roughly equivalent to Kotzebue Sound and is similar in many respects to Norton Sound to the south. The Seward Peninsula which separates them forms the eastern boundary of the Bering Strait. The greatest natural hazard in the area is ice, which is present nearshore about 9 months out of the year. Geologic considerations include subsurface discontinuous permafrost and ice-gouging. Oceanographic conditions are characterized by high waves, storm currents, and high winds.

A low coastal plain forms the shoreline of the Hope Basin planning area. The area is extensively used by breeding waterfowl, shorebirds and seabirds, as well as non-breeding migratory birds. The area also supports large numbers of breeding marine mammals and is the migratory corridor for the bowhead whale and other endangered wildlife (four whale species and two bird species) and non-endangered marine mammals.

Kotzebue is located in the eastern part of the planning area, and with the population of 2,500, is nearly as large as Barrow. It is a major arctic transportation and service center. Subsistence hunting and fishing, including for the bowhead whale, is a major use of the area.

1. Regional Geology

Hope Basin is a Late Cretaceous to Tertiary sedimentary basin. Its northern limit is defined by a zone of normal faults that parallel the southern flank of the northwest striking Herald Arch overthrust which lies to the north outside of the planning area. It is bounded on the south by an east-west trending basement ridge that may be an offshore extension of the Kobuk fault zone.

The basement throughout the area probably consists of Late Cretaceous or older rocks of the Brooks Range orogen. On the basis of seismic reflection character, refraction velocities, and relative stratigraphic position the basin fill probably is Late Cretaceous to Paleogene nonmarine mudstones, siltstones,

and sandstones, overlain by Neogene marine and nonmarine shales, and possibly sandstones with a combined total thickness locally exceeding 17,000 feet. The early Tertiary sediment fill is draped over the crest of basement highs and chaotically fills in the intervening troughs. The later Tertiary sediments have filled in the basin in sub-horizontal layers.

Northwest-southeast trending normal faults in the northern Hope Basin and east-west trending basement ridges in the southern Hope Basin are the dominant structural features. Generally, the basement is faulted into a ridge and trough configuration. The crests of some of these ridges are within 2,500 feet of the seafloor and the basement in the troughs reaches depths as great as 17,000 feet. In the northern part of the area, the ridges are essentially horst blocks or tilted normal fault blocks and in the southern part, the linear ridges, may be related to major strike-slip tectonics of the Kobuk fault zone. Basement faulting appears to have begun in the the late Cretaceous and continued into the mid-Tertiary. Tertiary normal faulting is of at least two generations: that directly related to active basement faulting and that created by compaction of the sedimentary section over basement highs.

2. Petroleum Potential

Two stratigraphic test wells drilled on native land, the Nimiuk Point No. 1 and the Cape Espenberg No. 1 wells, were drilled north and south of the entrance to Kotzebue Sound just east of the planning area in 1974 and 1975 by Standard Oil of California. The Kotzebue Sound wells penetrated from 3,500 to 4,000 feet of Quaternary sediments and from 2,500 to 4,000 feet of Tertiary rocks that lie on Devonian or older metasedimentary basement. The rocks in these wells show excellent reservoir properties with an average sand content for the total section of over 50 percent and average porosities over 25 percent. However, these favorable reservoir properties may be due to the proximity of the rocks to the source terrane and may not be representative for rocks in the deeper offshore Hope Basin.

Many structural, stratigraphic, and fault traps may exist in the basin on the crest of or adjacent to the basement horst blocks. However, because of poor potential for source rocks in the pre-Tertiary basement and the generally thin thermally immature Tertiary sedimentary section, the prospect for oil accumulation is low, with the possible exception of traps adjacent to locally thicker sections.

3. Geohazards

Water depths average about 120 feet but range to over 200 feet in the planning area. The dominant sediment type, covering the northern two-thirds of the seafloor in the Hope Basin, is modern current transported silts from the Yukon and other southern rivers. Near the Bering Strait relict or ice-reworked sand is prevalent, and wave sorted and tidal-current sand forms shoals and offshore bars on the northern coast of the Seward Peninsula.

Ice-gouging of the seafloor in the Hope Basin is generally less intense than in the Chukchi or Beaufort seas to the north. The gouges are more dense in water depths less than 120 feet and do not exist in water depths greater than 200 feet. The presence of these seafloor features is nearly ubiquitous throughout

the planning area but are more common nearshore and on the flanks of shoals. The orientation of the gouges is controlled by local bathymetry. Incision depths of the gouges average from about 6 feet to as deep as 15 feet.

Acoustic anomalies identified on seismic records indicate the possible presence of shallow gas in the Tertiary section. Whether these anomalies represent biogenic gas, which is probably not overpressured, or thermogenic gas accumulations, which may be overpressured, is not presently known.

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U. Chukchi Sea

This planning area is situated in the western portion of the arctic area north of Alaska and adjacent to the National Petroleum Reserve in Alaska. Promising geologic features cover virtually the entire planning area from the State-Federal boundary seaward.

Sea ice, including 9 months of shorefast ice and year-round offshore pack ice which can migrate inshore, is the chief obstacle to oil and gas operations. The planning area is also subject to severe arctic storms. Geologic hazards include subsea permafrost, erosion by ice and ice gouging, and thermogenic gas although none is presently reported in the Chukchi Sea.

The nearshore and onshore areas include productive lagoon and river delta habitats, which are critical seasonal feeding areas and breeding areas for migratory birds. The area is also used by a few species of marine mammals in large numbers, including the bowhead whale which is central to the subsistence lifestyle of area natives. Four endangered whale species and two endangered bird species inhabit the area seasonally.

Barrow is a major distribution center and regional government and native population center.

1. Regional Geology

Two geological provinces, the Chukchi Basin and the northern Hope Basin, exist within the planning area. Each exhibits a distinct stratigraphic sequence and has contrasting but tectonically related structural elements. These two provinces are separated by a prominent structural feature, the Herald Arch.

The three stratigraphic sequences present in the Chukchi Basin, Franklinian, Ellesmerian, and Brookian, appear to be an offshore extension of regional western North Slope stratigraphy. These sequences represent stages in the tectonic development and depositional history of the basin. The Franklinian sequence encompasses Cambrian to Late Devonian rocks which provided a stable platform for subsequent deposition and constitutes economic basement on the North Slope. The Ellesmerian sequence, Early Mississippian to Early Cretaceous in age, is comprised of transgressive shallow shelf marine carbonates, marine and nonmarine sandstone, and shale derived from a northerly source terrane. The Brookian sequence, Early Cretaceous to present age, is comprised of deep water to nonmarine northwardly prograding deltaic sediments.

The northern portion of the Hope Basin extends into the southern portion of this planning area. The block-faulted basement, possibly Cretaceous in age, is believed to be overlain by nonmarine to marine Tertiary clastic rocks.

The significant structural elements can be divided into two groups based on time of formation. These are the Paleozoic elements which include the Barrow Arch, Arctic Platform, Chukchi Platform, and the Hanna Trough, and the Mesozoic to Early Tertiary elements which include the North Chukchi Basin, Herald Arch, Northern Hope Basin, the Fold and Thrust Belt, and the Colville Trough.

2. Petroleum Potential

The first exploration permit for the Chukchi Sea planning area was issued in 1969. Although considerable interest has been exhibited by industry recently, no COST wells or exploratory wells have been drilled. Therefore, it is necessary to extrapolate stratigraphic relationships from well control in the adjacent National Petroleum Reserve in Alaska (NPRA). Exploration efforts in the NPRA area began in 1904 with surface geologic exploration and are continuing, although no major oil or gas fields have been discovered.

The best potential source rocks in the western NPRA and in the Chukchi Basin appear to be the Shublik Formation, the Kingak Shale, and the Pebble Shale of Ellesmerian age, and the Brookian Torok Formation, based on their high organic carbon content and high percentage of oil-prone kerogen. Vitrinite reflectance values indicate these rocks increase in thermal maturity and tendency for gas production to the south towards the Colville Trough.

The most prospective reservoirs in the planning area would appear to be the Lisburne Group, the Sadlerochit Group, the Shublik Formation, and the Sag River Formation which are all oil productive in the vicinity of Prudhoe Bay. The best potential reservoir rock is the Sag River sandstone due to its high sand content and high porosity values.

Both structural and stratigraphic traps are present in the planning area. Structural traps predominate in the Hanna Trough, North Chukchi Basin, and the Northern Hope Basin. Stratigraphic traps predominate in the Barrow Arch and Chukchi Platform regions.

The areas with the highest hydrocarbon potential appear to be the northeastern and western portions of the basin - the North Chukchi Basin, Barrow Arch, Arctic Platform, and the Chukchi Platform.

3. Geohazards

Potential geohazards include ice-seabed interactions, shallow gas accumulations, migrating bedforms, natural gas hydrates, coastal erosion, and sediment slumping near the shelf and on the slope. There is low probability of a large-scale seismic event and no evidence for subsea permafrost. Other hazards are storm surges and an extensive ice pack.

4. Supplemental Reading

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V. Beaufort Sea

This planning area, called Diapir Field in the 1982 program, includes continental shelf, slope, and abyssal plain physiographic provinces extending from the Canadian border past the western boundary of the planning area into the Chukchi Sea area. The geologic and meteorologic conditions are similar to those of Chukchi Sea. The region is a low coastal plain, characterized by numerous river deltas, such as the Colville River delta, lagoons, and barrier islands. This area supports the same type of avian and marine mammal populations as Chukchi Sea, except that bird populations are even higher. Two endangered whale species and two bird species inhabit the area seasonally.

The petroleum operations at Prudhoe Bay dominate the economy of the region. Nonetheless, while these employ area natives, subsistence activities remain extremely important both economically and culturally, especially the hunting of bowhead whales. Special stipulations have been applied in the past to leases in this region, including stipulations restricting oil and gas operations when they might interfere with bowhead whale migration.

1. Regional Geology

The Beaufort Shelf is divisible into two major provinces, including: (1) a landward area underlain by ancient continental crust termed the Arctic Platform; and (2), an area near the shelf-edge where thick clastic wedges of Cretaceous and Tertiary sediments were deposited in part upon Mesozoic oceanic crust. The highly faulted boundary between these provinces is termed the Hinge Line.

Acoustic and economic basement on the Arctic Platform consists of a metamorphic complex (Franklinian Sequence) which represents the roots of an Early Paleozoic orogen. Basement is overlain by Devonian through Jurassic strata (Ellesmerian Sequence) deposited in a stable shelf setting. The Ellesmerian Sequence thins and onlaps northward toward the ancient landmass which once existed north of the modern Beaufort continental margin. Ellesmerian sedimentation terminated in Late Jurassic time with the thermal uplift of the Arctic Platform prior to rifting in the vicinity of the present shelf edge. This uplift produced a regionally extensive Lower Cretaceous unconformity and erosional truncation of Ellesmerian strata across the northern part of the Arctic Platform. The subsequent onset of actual rift displacement produced intrarift grabens which were filled with Lower Cretaceous sediments (Rift Sequence) derived from adjacent highlands. Cooling and subsidence of the near-rift crust following breakup created the modern Barrow Arch. By Late Cretaceous time, an immense clastic wedge prograding northward from the Brooks Range orogen inundated and spilled over the Barrow Arch into depocenters along the newly-formed, fault-bounded, Beaufort continental margin. Most of the eastern Beaufort shelf is underlain by Cenozoic sediments which were deposited in this setting.

2. Petroleum Potential

Exploration for hydrocarbons in the area has been conducted since 1944, when the Department of the Navy began drilling exploratory tests at a host of localities in the central parts of the Arctic coastal plain. This work led to the discovery of several subcommercial oil and gas fields. Privately-funded exploration elsewhere on the coastal plain led to the discovery of the supergiant Prudhoe Bay field in 1968. This field contained original recoverable reserves in excess of 10 billion barrels of oil and 26 trillion cubic feet of gas.

The Prudhoe Bay field sparked oil development in northern Alaska and afforded construction of an essential pipeline transportation system from the field to an ice-free port in southern Alaska. Because of the existence of this infrastructure, other accumulations in the vicinity of Prudhoe Bay, which would otherwise be considered subcommercial (ranging from 0.3 to 1.0 billion barrels), are now being brought into production. The only proven commercial accumulation known to extend into Federal waters is the Seal Island field. The Seal Island discovery was announced by Shell in early 1984 and total recoverable reserves are presently estimated at 300 million barrels.

Three lease sales have been held in the Beaufort Sea. The most recent OCS lease offering (Sale 87) was held in August 1984. The part of the Chukchi shelf now included within the planning area has not been included within any previous sales. Nine exploratory wells have been completed on Federal acreage as of September 1, 1985.

Most major North Slope oil accumulations are contained in Ellesmerian Sequence reservoir formations, and any part of the Arctic Platform where these rocks are preserved is considered highly prospective. Known accumulations are trapped by a complex composite of sealing mechanisms, including faults, structural dip, and truncation at regional unconformities such as that associated with the major Lower Cretaceous erosional event. The northernmost parts of the Arctic Platform are less prospective because of the absence of Ellesmerian formations, but contain intrarift grabens within which excellent reservoir rocks deposited as

part of the Rift Sequence may be present. Excellent oil source beds are thought to be present at levels of thermal maturity adequate for oil generation and expulsion in all parts of the Beaufort shelf within the planning area.

Numerous structural and stratigraphic traps exist within the thick clastic wedge seaward of the Hinge Line. Any potential reservoir sands in this area were most likely deposited in a deltaic or prodelta setting, suggesting that individual accumulations may be small due to reservoir lenticularity. This has been found to be the case in analogous geological provinces, such as the Mackenzie delta area of the Canadian Beaufort shelf. Rotational folds associated with listric faulting are the most attractive targets in the western area, while compressional folds and fault-traps are the most prevalant trap configurations in the eastern area.

Because of the narrow width of the Beaufort continental shelf, most of the planning area is underlain by the abyssal plain of the Arctic Ocean. On the basis of geological and logistical considerations, only the continental shelf extending out to the 200-foot isobath is thought to have any realistic potential for the occurrance of economic accumulations of hydrocarbons.

3. Geohazards

Geological features which may affect petroleum-related activities on the Beaufort shelf include seasonal ice cover, permafrost, strudel scouring, shallow gas, abnormal formation pressure, shallow faults, seismicity, and unstable seafloor sediments. Ice movement may exert great stresses upon surface structures and ice gouging may require burial of seafloor installations such as pipelines. Spring-flood strudel scouring of the seafloor near the mouths of major rivers is a design consideration for any installations placed there. Shallow gas may be trapped in several ways on the shelf, and constitutes a potential hazard to drilling operations. Abnormally-high pore pressures have been measured in Cenozoic strata in wells in the eastern part of the Planning Area and the nearby Canadian Beaufort. Moderate-magnitude earthquake activity has been documented in the eastern Beaufort shelf. Surface fault displacements and sediment slumps triggered by earthquakes constitute a potential hazard to seafloor installations, particularly pipelines. Geohazards also include subsea permafrost and natural gas hydrates, current transport and sediment scour, coastal erosion, migratory shoals, and sediment slumping near the shelf break. Other hazards are over ice flooding and storm surges.

4. Supplemental Reading

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Table H-1

Some Ecological Characteristics of OCS Planning Areas

Planning Areas	Acreage[1] (million)	Threatened and Endangered Species[2]	Marine Mammals[2]	Birds[2,3]
North Atlantic	49	2 Birds 5 Turtles 6 Whales	31 species; major feeding ground	11.8 M; moderate shorebirds; breeding seabirds
Mid-Atlantic	82	2 Birds 5 Turtles 6 Whales	32 species; migratory and feeding area	4.9 M moderate shorebirds; breeding seabirds
South Atlantic	99	5 Birds 5 Turtles 6 Whales Manatee	32 species; Right Whale breeding area	2.3 M (1.1 M breed)
Straits of Florida	8	4 Turtles 5 Whales Manatee	31 species; Manatee migratory and feeding area	25 species; migrant and non-migrant shorebirds, wading birds, and waterfoul
Eastern Gulf of Mexico	58	5 Birds 5 Turtles 5 Whales Manatee	25 species (1 species breeds); 1,700 individuals breed	300,000 (130,000 breed); seabirds
Central Gulf of Mexico	46	5 Birds 5 Turtles 5 Whales	25 species (1 species breeds); 1,200 individuals breed	3.9 M (2.8 M breed); non-breeding seabirds
Western Gulf of Mexico	35	5 Birds 5 Turtles 5 Whales	25 species (1 species breeds); 1,200 individuals breed	3.6 M (2.6 M breed); non-breeding seabirds
Southern California	30	5 Birds 4 Turtles 7 Whales Southern Sea Otter	32 species (8-10 species breed); over 80,000 pinnipeds breed	14 species (60,000 birds) breed; 80 species breeding and non-breeding
Central California	15	6 Birds 4 Turtles 7 Whales Southern Sea Otter	18 species (8-10 species breed); over 150,000 individuals, (10,000 pinnipeds breed)	16 species (0.3 M birds) breed

Table H-1 (con't)

Some Ecological Characteristics of OCS Planning Areas

Planning Areas	Acreage[1] (million)	Threatened and Endangered Species[2]	Marine Mammals[2]	Birds[2,3]
Northern California	29	6 Birds 4 Turtles 7 Whales	18 species (6-8 species breed); over 20,000 individuals, (6,000 pinnipeds breed)	16 species (0.3 M birds) breed
Washington-Oregon	47	4 Birds 2 Turtles 7 Whales Alaska Sea Otter	28 species; 2 species of pinnipeds breed	20-30 offshore species; 1.6 individuals/Km^2
Gulf of Alaska	133	7 whales 4 birds	14 species (at least 3 species breed); greater than 35,000 individuals breed	1) 2.1 M 2) Greater than 20 M 3) 849 birds/Km^2
Kodiak	89	7 whales 3 birds	14 species (at least 4 species breed); greater than 35,000 individuals breed	1) 1.0 M 2) N/A 3) 1831 birds/Km^2
Shumagin	83	7 whales 3 birds	14 species (at least 3 species breed); greater than 25,000 individuals breed	1) 4.6 M 2) N/A 3) 363-2858 birds/Km^2
Cook Inlet	5	3 whales	15 species (at least 4 species breed); greater than 40,000 individuals breed	1) 0.4 M 2) N/A 3) 197-111 birds/Km^2
North Aleutian Basin	32	8 whales 4 birds	20 species (at least 6 species breed); greater than 100,000 individuals breed	1) 1.9 M 2) 0.5 M 3) 245-2457 birds/Km^2

Table H-1 (con't.)

Some Ecological Characteristics of OCS Planning Areas

Planning Areas	Acreage[1] (million)	Threatened and Endangered Species[2]	Marine Mammals[2]	Birds[2,3]
St.George Basin	70	8 whales 3 birds	19 species (at least 5 species breed); greater than 1.5 M individuals breed	1) 5.0 M 2) N/A 3) 655-1797 birds/Km²
Navarin Basin	37	6 whales 2 birds	16 species (at least 6 species breed); greater than 50,000 individuals breed	1) 0 2) 0 3) 97-193 birds/Km²
Norton Basin	25	5 whales 3 birds	14 species (at least 5 species breed); greater than 10,000 individuals breed	1) 2.2 M 2) Greater than 1 M 3) 343-775 birds/Km²
Hope Basin	12	4 whales 2 birds	8 species (at least 4 species breed); greater than 100,000 individuals breed	1) 1.7 M 2) N/A 3) 775 birds/Km²
Chukchi Sea	29	4 whales 2 birds	8 species (at least 4 species breed); greater than 100,000 individuals breed	1) 0.16 M 2) 0.5 M 3) N/A
Beaufort Sea	52	2 whales 2 birds	19 species (at least 3 species breed);greater than 50,000 individuals breed	1) Greater than 0.1 M 2) N/A 3) 50-100 birds/Km²

[1] Planning area acreages are approximate and subject to revision.

[2] Data from MMS offices, reported from numerous sources.

[3] Table entries for Alaska planning areas are shown for the following categories: (1) Colonial Seabirds, (2) Coastal Migration and Nesting, and (3) High Density.

N/A = Not Available or Not Applicable; M = Million

III. Other Uses of the OCS

A table showing uses of the sea and seabed is included in this appendix at the end of this section (Table H-2).

A. Summary of Department of Defense Operations on the U.S. Outer Continental Shelf

Following is a description of Department of Defense (DOD) operations by Outer Continental Shelf (OCS) planning area. Discussions of classified operations are omitted.

1. North Atlantic

Portions of the water and air space of the North Atlantic OCS and adjacent shoreline are used for various military operations essential to training, readiness, and support of national defense and security interests. These operations include training and testing activities such as submarine operations, gunnery practice, sea trials, radar tracking, vessel maneuvers, and general operations. These activities normally take place in areas specifically designated for such purposes that are under the control of the DOD.

The Narragansett Bay Operating Area (NBOA) is one of the major training and operating areas used by the attack submarines assigned to the Atlantic Fleet. Approximately 30 percent of these submarines have Groton/New London, Connecticut as their home port and regularly use this operating area along with newly constructed submarines undergoing sea trials and certification. Operating areas were established for training of surface, submarine, and air units and to provide designated zones for testing ordnance, aircraft, and ships.

U.S. Air Force (USAF) use of North Atlantic areas include basic fighter maneuvering, air combat training, and air-to-air intercepts.

2. Mid-Atlantic

Ten submarine lanes and five Warning Areas have been identified as being necessary to DOD. The port of Norfolk, Virginia and its surrounding area is the home port for the majority of U.S. Atlantic Fleet air and surface units. A complex network of facilities is concentrated in this region to support Atlantic Fleet operations, training and readiness requirements associated with the deployment of units to the various theaters, and preparing them for contingency operations in other areas.

The Fleet Combat Training Center at Dam Neck, Virginia uses W-50 to train gunnery students in surface-to-surface and surface-to-air firing from fixed shore installations.

W-386 provides multiple training areas for numerous independent and integrated operations. Surface and airborne drone targets are used for surface and air weapons delivery including strafing, rockets, and bombs. Anti-submarine rocket and torpedo firings are routinely conducted. The Naval Air Test Center (NATC), Patuxent River launches a variety of missiles into the area with wide hazard footprints. The NATC has responsibility for

the conduct of TOMAHAWK cruise missile firings for east coast surface and subsurface combatants. NATC operations in both W-386 and W-108 involve full mission flight profiles of extended low level cruise missile flights requiring tracts free of surface traffic and structures.

W-72A is primarily used for aircraft live missile firing. Radar coverage and missile impact and safety zone considerations preclude increasing the distance from shore or changing the size of the area required for these operations.

The NATC is the prime user of W-108. NATC is the Navy's principal development and test site for naval aircraft and their associated weapons systems. NATC conducts 500 to 700 test flights per year using both W-108 and W-386. Tests involve supersonic flying at high and low altitudes, air-to-air and air-to-surface missile firings, anti-submarine warfare systems evaluation, and electronic warfare system evaluations. The footprints of the missiles fired cover several hundred square miles and electronic emissions have the potential to disrupt commercial communications systems.

USAF activities in the Mid-Atlantic include readiness training for tactical fighters and interceptor aircraft, refueling operations, basic fighter maneuvering, air combat training, and air-to-air intercepts. Live ammunition is expended.

3. South Atlantic

The Cape Canaveral Operating Area, submarine transit lanes off the coasts of North Carolina, South Carolina, and Florida, and the Flight Clearance Zone (FCZ) of the Kennedy Space Center (KSC) comprise the operating zones of concern in the South Atlantic area. The operating area supports ballistic missile submarine operations including the launch of test missiles and special sonar tests. The area encompasses a unique combination of launch areas and support facilities associated with submarine launched ballistic missiles of the United States and United Kingdom. Launch area positionings are predicated on unique flight path clearances and range safety restrictions for POLARIS, POSEIDON, and TRIDENT test missiles. The Air Force has safety responsibilities in the KSC FCZ for missile and space shuttle launches from KSC.

Submarine transit lanes provide safe and secure submerged transit corridors to and from submarine training and operating areas for the submarine ports of Jacksonville, Charleston, and Norfolk.

Warning Area 174 extends from the Eastern Gulf of Mexico into the Dry Tortugas and the Florida Keys. This area is used for carrier operations described above. Additional information on use of this area is expected.

4. Gulf of Mexico

The two types of operations conducted by the Navy in the Gulf of Mexico which can conflict with oil and gas activities are carrier operations and Naval Coastal Systems Center (NCSC) research and development activities. A training carrier is permanently based in Pensacola, Florida to qualify student naval aviators in carrier operations before they are designated as Naval Aviators

and receive assignments to more advanced training. These military operations are conducted in W-228 offshore Corpus Christi, Texas; in W-155 offshore Pensacola, Florida, and in W-174 offshore Key West, Florida. The carrier requires an area free of obstructions approximately 60 miles in diameter within 75 miles of a suitable divert field in which to operate.

The NCSC at Panama City, Florida is the principal research, development, test, and evaluation (RDT&E) center for the application of science and technology to military operations in coastal regions. The NCSC's operations include RDT&E support to mine countermeasures, diving and salvage, acoustic countermeasures, environmental technology, inshore warfare, anti-submarine warfare, and amphibious operations. These operations are conducted within a 44 nautical mile arc of a fixed point offshore Panama City.

USAF activities include basic fighter maneuvering, air combat training, air-to-air intercepts, trailing of wire antennae, and aerobatics. Live ammunition is expended.

Both the Air Force and Navy use warning areas which encompass most of the Eastern Gulf of Mexico for air-to-air and air-to-surface missile operations originating at Eglin Air Force Base, Florida.

5. Southern California

The Southern California area contains a massive integrated complex of operating areas designed to accommodate a wide spectrum of specialized warfare training, exercises, and research and development. Almost half of the U.S. Pacific Fleet's 240 ships and 1000 aircraft are based in Southern California. Because of the area's unique geographical features, the Navy has located extensive, sophisticated, instrumented ranges along the Southern California coast and offshore. Most of the Navy's research, development, and testing of new missiles, torpedoes, and other weapons as well as Pacific Fleet weapons proficiency firings in support of air, surface, and sub-surface training are conducted on these ranges. The proximity of specialized multiple operating areas to the major home port of San Diego and surrounding bases and facilities permits necessary intensive training schedules for surface, sub-surface, and air units confronted with minimum turn-around times to prepare for forward deployments to the Pacific theater and Indian Ocean.

The Pacific Missile Test Center (PMTC) at Point Mugu, California, conducts research, development, testing, and evaluation of new DOD weapons systems; conducts evaluation of operation weapons systems; and coordinates numerous exercises in assurance of fleet air and surface unit readiness. More than 1400 missile launch operations are scheduled annually. Programs and operations include: TOMAHAWK air launched Cruise Missile; AEGIS; HARPOON; SPARROW; PHOENIX; high speed antiradiation missile; Rolling Airframe missile; close in weapons systems; high energy laser; HASP and ROBIN meteorological rockets; fleet unit surface-to-air, air-to-air, and air-to-surface missile exercises; and fleet underwater exercises.

The Shallow Water Coordinated Anti-Submarine Warfare Service and Training Area 1 (CAST 1) is an anti-submarine training area, unique for shallow water conditions. Air, surface, and submarine platforms expend weapons and sonobuoys. Towed array devices and variable depth sonar operations are conducted as well as low altitude ASW aircraft operations. Live ordnance is expended.

The Coordinated ASW Services and Training Area 2 (CAST 2) is the primary area for coordinated air, surface and submarine anti-submarine warfare training. Air, surface, and submarine platforms expend live ordnance (including acoustic homing torpedoes) and sonobuoys in the area. Towed array devices and variable depth sonar operations are conducted as are low altitude ASW aircraft operations.

The Shallow Water Coordinated ASW Services and Training Area 3 (CAST 3) is used for air, surface, and submarine coordinated operator training with similar hazardous operations as in CAST 1. It is specially designed to provide sea room in conjunction with an instrumented facility for exercising new ASW long range sensors and weapons. Air, surface, and subsurface weapons and sonobuoys are expended, including live ordnance. Low altitude aircraft operations are conducted.

Fleet Training Area HOT (FLETA HOT) is used for air, surface, and submarine weapons training, large scale fleet exercise, and carrier refresher training. It includes an anti-submarine warfare training area (CAST 2) with operations similar to those performed in CAST 1. The area is used to integrate multi-weapons training operations and includes live ordnance expenditures.

The Combat System Evaluation Range/Shipboard Electronics Evaluation Facility is used for evaluating shipboard antenna radiation patterns, passive electromagnetic direction finding calibrations and electronic systems testing in conjunction with fixed shore facilities which cannot be relocated without great expense and deferral of another area of equal size.

The Camp Pendleton Amphibious Assault Area is an area in which amphibious operations are conducted. These include low altitude bombing, rocket firing and strafing, free balloon operations, submarine operations, and surface warfare training. This is the sole eastern Pacific location for full scale amphibious operations training.

The Encinitas Naval Electronic Test Area is used for surface ship and submarine operations which include torpedo firing and live ordnance as well as research and development projects.

The Fleet Training Area COLD is used for surface ship and submarine operations including torpedo firing and live ordnance. It also contains Naval Ocean Systems Center research and development projects.

The Santa Cruz Acoustic Range Facility is used for surface ship and submarine acoustic signature measurement and ascoustic research and development by the Naval Oceanographic Systems Command. This area is predominantly contained within the PMTC range.

The Coronado Island Submarine Training Area is used as a surface ship rendezvous point when exiting port and for amphibious ship training involving anchoring and landing craft launching. It includes low altitude helicopter operations involving dipping sonar, sonobuoy, and torpedo operations. Live ordnance is expended. The Tactical Maneuvering Area P-4 and Portion of W-291 connecting P-4 to FLETA HOT is used for tactical air combat training, air intercept training, air-to-air gunnery, and missile training including live ordnance.

Five submarine transit lanes pass through this area. These require unencumbered sea room for submerged transit critical for safe navigation.

The San Clemente Island Fire Area is used for long range weapons firing, drone operations (air and sea), weapons test firing, short range missile firing, air interception control and air combat training.

The San Clemente Island/Training Area is used for underwater demolition team training, underwater warfare research and development, sensor and navigation systems calibration, and weapon system acceptance tests.

The shore Bombardment Area is used for shore bombardment, bombing, strafing, rocket deliveries, drone operations, and close air support training. Live ordnance is expended.

USAF activities include basic fighter maneuvering, air combat training, and air-to-air intercepts.

The Southern California offshore area also contains impact areas for Space Shuttle solid rocket booster and external tank equipment associated with the national space program. Impacts and the impact area are similar to those of KSC in Florida.

The Space Shuttle footprint originates at Vandenberg Air Force Base in this area and extends into Central California. In addition, polar orbiting satellites and intercontinental ballistic missiles and other missiles in the testing stages are launched from various sites at Vandenberg AFB.

6. Central and Northern California

Central and Northern California Naval Operating Zones, a complex system of training and operating areas, are located between Point Conception and the northern border of California. These areas are associated with combat readiness of Pacific Fleet units operating primarily from central and northern California ports.

Warning Area W-532 is in the northern sector of the Pacific Missile Test Center (PMTC). PMTC, located at Point Mugu, California, conducts several hundred weapons systems launches each year. Launch operations are within defined limits, and the surface area within these areas and the air space above must be clear throughout the launch.

Point Reyes Warning Area W-513 is used for all-weather flight training, air intercepts, and surface operations. Live ordnance is not used in this area.

Point Reyes Electronic Range Zone is an acoustically augmented electronic range in which newly overhauled submarines are tested. San Francisco Submarine Diving Areas Uniform 1, 2, 3, 4, and 5 are surveyed locations in which the hulls of submarines are tested to assure safety. Two submarine transit lanes are used for secure submerged transit by submarines. CAST Central is a coordinated anti-submarine warfare training area in which sonobuoys and depth charges are employed.

Warning Areas W-260, W-283, and W-285 are areas used for all-weather flight training, anti-submarine warfare training, and surface operations. Aerial gunnery and air-to-surface weapons are used in this area.

7. Washington-Oregon

Submarine Operating Area Oscar is used for surface and subsurface tactical exercises, independent and multi-ship exercise, equipment tests and machinery trials.

Submarine Trial and Test Areas 3 and 4 are used for surface/subsurface tactical exercises and including equipment tests and machinery trials.

Three Submarine Transit Lanes pass through this area.

The Explosive and Chemical Dumping Areas located at Cape Flattery and the Columbia River Mouth are located in about 850 and 790 meters of water, respectively.

Warning Area 460 is used for exercise involving air to air gunnery, rockets, missiles, air to surface firing, bombing, missiles, conventional ordnance, and photoflash cartridges. Part of the area is also designated as an anti-submarine warfare training area in which sonobuoys, practice depth charges, and smoke markers are used.

Surface Exercise Area 601 is used as an ocean surface operating area using surface tactical gunnery including anti-aircraft firing and missile firing, undersea warfare exercises, and combined type exercises. Ordnance including rockets, missiles, torpedoes, incendiaries, photoflash, illumination, and gun type ammunition may be used.

Warning Area 601 is used for air to surface intermediate and low altitude bombing, strafing, and rocketry utilizing conventional ordnance and photoflash cartridges.

Sea Lion Rock is a special use area with a water target of a barren unmarked rock.

W-237A is used for air to air gunnery and rocketry, air to surface firing and bombing using conventional ordnance and photoflash cartridges.

Washington Coastal Surface Exercise Areas 237N and 237S is used for exercises involving surface tactical gunnery including anti-aircraft and missile firing. Undersea warfare and combined exercise are also conducted in these areas. Ordnance including rockets, missiles, torpedoes, incendiaries, photoflash, and illumination and gun type ammunition may be used.

Warning Area 570 is used for air intercept, aerobatics, and inflight refueling training.

USAF activities include basic fighter maneuvering, air combat training, and air-to-air intercept training.

8. Alaska

None.

B. NASA Operations Zones

Following is a description of the National Aeronautics and Space Administration (NASA) operations by OCS planning area.

1. Mid-Atlantic Planning Area

In order to avoid operational conflicts with NASA activities, NASA prefers to have some 510 blocks encompassing an estimated 2.9 million acres, which is their entire operations zone in the Mid-Atlantic planning area, removed from leasing consideration. Removal of the blocks would eliminate the possibility of an exploratory rig and/or production platform from being damaged by falling debris from rocket and missile tests.

2. South Atlantic Planning Area

The NASA Kennedy Space Center (KSC) is the principal launch and recovery site for the Space Transportation System, as well as the launch site for a variety of other space launch vehicles. The Space Transportation System, both civilian and military, is expected to continue in that capacity for a number of years. The system is now operational and the number of flights are increasing each year.

3. Southern California Planning Area

The Air Force's (as well as NASA's) concern in this area (Vandenburg Air Force Base Space Shuttle Impact Area) is that solid rocket booster (SRB) fragments from early launch aborts will result in an explosive force upon surface contact that may be hazardous for exposed personnel. Also of concern is the ability to recover the reusable SRB's from normal launches.

NASA and the Air Force requested that this area be excluded because of the hazard potential. This zone includes impact areas for Space Shuttle Solid Rocket Boosters and External Tank equipment associated with the National Space Program. The so called "foot print" extends about 143 nautical miles from shore over the DOI Southern California Planning Area.

C. Navigation Zones

The Ports and Waterways Safety Act charges the U.S. Coast Guard with the responsibility to take measures to provide safe access routes for vessel traffic proceeding to or from ports. These measures entail establishing traffic separation schemes (TSS) which divide traffic into designated inbound and outbound lanes. Designations within the TSS include the following:

- Traffic Lanes - the inbound and outbound lanes in which vessels must navigate.
- Separation Zone - the zone dividing the two traffic lanes which is used only for crossing purposes.
- Precautionary Area - a segment in which vessels must navigate with special caution and within which certain directions of traffic flow may be suggested.
- Fairway - a corridor in which all structures are prohibited.

Areas designated as Precautionary Areas, Traffic Lanes and Fairways do not allow any navigational obstruction within their boundaries.

A description of navigation zones by planning areas is presented below.

1. North Atlantic Planning Area

TSS's and Precautionary Areas have been established at the approaches to Portland and Boston Harbors, and Narragansett and Buzzards Bays.

2. Mid-Atlantic Planning Area

TSS's and Precautionary Areas have been established at the approaches to Narragansett, Buzzards, New York, Delaware, and Chesapeake Bays.

3. Eastern, Central, and Western Gulf of Mexico Planning Areas

A system of fairways connecting major Gulf ports and the deepwater oil terminal (LOOP) off Louisiana controls traffic in open Gulf waters.

4. Southern California Planning Area

TSS's and Precautionary Areas have been established for major Southern California ports.

5. Central California Planning Area

TSS's and Precautionary Areas have been established for the approach to San Francisco, and the Coast Guard is in the process of amending these zones to provide even safer port access.

Table H-2

Some Other Uses of the Sea and Seabed by OCS Planning Area

Planning Area	Commercial[1] Fisheries: Thousand Tons Landed Per Year	Commercial[1] Fisheries: Million $ (1983)	Recreational[2] Fisheries (Thousand Tons Per Year)	Coastal[3] Travel and Tourism (Million $ Per Year)	Subsistence[4] Hunting and Fishing Dependence	Military[5] and Aerospace Use	Navigation[6] Zones
North Atlantic	784	528	13	1,050	N/A	M	E
Mid-Atlantic	141	157	71	5,820	N/A	M	E
South Atlantic	481	140[b]	35	20,560	N/A	M	N/A
Straits of Florida	43	19	11	4,300	N/A	L	N/A
Eastern Gulf of Mexico	100	95[b]	-[e]	8,500	N/A	H	E
Central Gulf of Mexico	1,134	324	27[e]	3,200	N/A	L	E
Western Gulf of Mexico	47	188	-[e]	4,700	N/A	L	E
Southern California	205	152	N/A	2,964	N/A	H	E
Central California	32	26	N/A	1,539	N/A	L	E
Northern California	28	24	N/A	65	N/A	L	N/A

Table H-2 (Continued)

Some Other Uses of the Sea and Seabed by OCS Planning Area

Planning Area	Commercial Fisheries[1] Thousand Tons landed Per Year	Commercial Fisheries[1] Million $ (1983)	Recreational[2] Fisheries (Thousand Tons Per Year)	Coastal[3] Travel and Tourism (Million $ Per Year)	Subsistence[4] Hunting and Fishing Dependence	Military[5] and Aerospace Use	Navigation[6] Zones
Washington-Oregon	123	100	N/A	N/A	N/A	L	N/A
Gulf of Alaska	292.6[a]	232[c]	N/A	87.5	One third of native families receive more than one half of their food supply from subsistence resources.	L	N/A
Kodiak	102.8[a]	91[c]	N/A	10.45	"	L	N/A
Shumagin	23.9[a]	21[c]	N/A	5.5	"	L	N/A
Cook Inlet	58.4[a]	50[c]	N/A	209.0	"	L	N/A
North Aleutian Basin	206.2[a]	115[c]	N/A	.55	One half of native families receive more than one half of their food supply from subsistence resources.	L	N/A
St. George Basin	40.3[a]	24[c]	N/A	11.0	About two thirds of native families receive more than one half of their food supply from subsistence resources.	L	N/A

Table H-2 (Continued)

Some Other Uses of the Sea and Seabed by OCS Planning Area

Planning Area	Commercial Fisheries[1] Thousand Tons landed Per Year	Commercial Fisheries[1] Million $ (1983)	Recreational[2] Fisheries (Thousand Tons Per Year)	Coastal[3] Travel and Tourism (Million $ Per Year)	Subsistence[4] Hunting and Fishing Dependence	Military[5] and Aerospace Use	Navigation[6] Zones
Navarin Basin	27.3[a]	27[c,f]	N/A	.05	_[f]	N/A	N/A
Norton Basin	10.6[a]	2[c]	N/A	2.2	About two thirds of native families receive more than one half of their food supply from subsistence resources.	N/A	N/A
Hope Basin	3.8[a]	2[c]	N/A	1.65	"	N/A	N/A
Chukchi Sea	0	_[c,d]	N/A	5.5	"	N/A	N/A
Beaufort Sea	0	_[c,d]	N/A	11.0	"	N/A	N/A

[1] U.S. Department of Commerce, National Marine Fisheries Service, Fishery Statistics of the United States, 1983, Washington, D.C., April 1984, pp. 4-5. Reported State landings were allocated to conform to planning areas in some cases, based on landings by port.

[2] Atlantic Planning Areas: NOAA. 1984. Current Fishery Statistics No. 8322. Actual data are from 1979; Gulf of Mexico Planning Areas: NOAA/NMFS. 1982 Marine Recreational Fishery Statistics Survey - Atlantic and Gulf Coast. Bell, F. W.; Sorensen, P. E.; Leeworthy, V. R., 1982. The Economic Impact and Valuation of Saltwater Recreational Fisheries in Florida.

Table H-2 (Continued)

Some Other Uses of the Sea and Seabed by OCS Planning Area

[3]Atlantic Planning Areas: Data from various State documents and offices; data not necessarily comparable.
Gulf of Mexico Planning Areas: U.S. Department of the Interior, Minerals Management Service, 1984, Draft EIS for Proposed Lease Sales 94/98/102, Washington, D.C. Pacific and Alaska Planning Areas: Data from MMS Regional Offices, reported from many State and other sources; data not necessarily comparable.

[4]Data, where applicable, are from MMS Regional Offices, reported from many States and other sources; data are not necessarily comparable.

[5]Military and Aerospace Use: L=Low, M=Medium, H=High.

[6]Navigation Zones = traffic separation schemes, pathways, anchorages, etc. which are officially established; data for the Gulf of Mexico are from the U.S. Coast Guard, 7th and 8th Districts; E = established zones.

a. Amount shown is in millions of pounds.
b. Data for the east and west coasts of Florida provided by Mr. Ronald Schultze, National Marine Fisheries Service, Woods Hole, August 21, 1984. See Appendix G, Table II.A.2.1., Footnote b.
c. The 1983 value of landings for these areas was estimated by allocating the region-specific landings reported in State of Alaska, Alaska 1982 Catch and Production (July 1984) to each Alaskan OCS planning area. All 1982 dollars were converted to 1983 values.
d. Value equals less than one million dollars.
e. Amount shown for Central Gulf of Mexico is for the entire Gulf of Mexico.
f. There is no civilian population in this area.

N/A = Not Available or Not Applicable

IV. Leasing and Development History of Planning Areas

Section 18(a)(2)(E) of the OCS Lands Act Amendments requires that the timing and location of exploration, development and production among physiographic OCS regions be based on a consideration of the interest of potential oil and gas producers, as indicated by exploration or nomination. Section 18(a)(3) requires that one consideration which must be balanced in the selection of the timing and location of leasing is the potential for discovery of oil and gas.

Tables H-3 and H-4 show pertinent information concerning leasing history and hydrocarbon development and production. Leasing history is indicated by the number of previous lease sales and by the total acreage leased and by acreage currently under lease by planning area. Hydrocarbon development is shown by cumulative production, total wells drilled, and by remaining recoverable reserves. The information presented in Table H-3 is important for assessing the likelihood of future hydrocarbon discoveries and for understanding the interest of potential producers. The rankings of interest by potential producers is in Appendix D. A brief history of OCS leasing is included in Appendix F.

Table H-3

Leasing and Development History by OCS Planning Area

Planning Area	Prev. Lease Sales	Total Acres Leased (million)	Acres Under Lease (million)	Cumulative Production: million bbl/oil & cond.	Cumulative Production: trillion cf/gas	Total Wells: Expl.	Total Wells: Dev./Prod.	Remaining Recoverable Reserves[1]: Oil (million bbl)	Remaining Recoverable Reserves[1]: Gas (trillion cu. ft.)
North Atlantic	1	0.4	0.3	0	0	8[a]	0	0	0
Mid-Atlantic	4	1.3	0.6	0	0	32[a]	0	0	0
South Atlantic	3	0.6	0.4	0	0	6[a]	0	0	0
Stratis of Florida	0	0.0	0.0	0	0	0	0	0	0
Eastern Gulf of Mexico	8	1.7[b]	1.3[c]	0	0	27[a]	0	-[g]	-[g]
Central Gulf of Mexico	41	17.1[b]	12.4[c]	6,003[e]	56.8[e]	19,179[f]	-[f]	3,670[g]	44.5[g]
Western Gulf of Mexico	24	9[b]	6.6[c]	89[e]	5.2[e]	2,676[f]	-[f]	-[g]	-[g]
Southern California	9	1.6	.9	279[e]	.1[e]	273[d]	430	1,250	2.2
Central California	1	.2	0	0	0	12	0	0	0
Northern California	1	.1	0	0	0	7	0	0	0
Washington-Oregon	1	.6	0	0	0	12	0	0	0

Table H-3 (con't)

Leasing and Development History by OCS Planning Area

Planning Area	Prev. Lease Sales	Total Acres Leased (million)	Acres Under Lease (million)	Cumulative Production: million bbl/oil & cond.	Cumulative Production: trillion cf/gas	Total Wells: Expl.	Total Wells: Dev./Prod.	Remaining Recoverable Reserves[1]: Oil (million bbl)	Remaining Recoverable Reserves[1]: Gas (trillion cu. ft.)
Gulf of Alaska	3	.6	.04	0	0	12[a]	0	0	0
Kodiak	0	0	0	0	0	0	0	0	0
Shumagin	0	0	0	0	0	0	0	0	0
Cook Inlet	3	.6	.07	0	0	13[a]	0	0	0
North Aleutian Basin	0	0	0	0	0	0	0	0	0
St. George Basin	1	.5	.5	0	0	9[a]	0	0	0
Navarin Basin	1	1.2[h]	1.2[h]	0	0	3[a]	0	0	0
Norton Basin	1	.3	.3	0	0	3	0	0	0
Hope Basin	0	0	0	0	0	0	0	0	0
Chuckchi Sea	0	0	0	0	0	0	0	0	0
Beaufort Sea	3	2.0[i]	2.0[i]	0	0	9[a]	0	0	0

[1] Remaining Recoverable Reserves as of December 30, 1983

[a] Wells completed as of September 1, 1985.

[b] Total acres leased is more than actual acres leased because of releasing.

[c] Acres under lease as of 3/28/84 Eastern Gulf of Mexico; 12/7/83 in Central Gulf of Mexico; and 9/28/84 in Western Gulf of Mexico.

[d] Wells completed as of December 31, 1984.

[e] Cumulative production from MMS Federal Offshore Statistics September 1984.

[f] Total for all wells is included in exploration wells; figure is as of June 30, 1984.

[g] Amount of remaining recoverable reserves shown for the Central Gulf of Mexico is for the entire Gulf of Mexico OCS.

[h] Includes 96,800 acres (17 leases) in dispute because of Russian boundary question.

[i] Includes 25,859 acres (4 leases) in dispute because of the Canadian boundary question.

Table H-4

ALL LEASE OFFERINGS

Lease Offering	Date of Offering	Location	No. of Tracts Offered	Acres Offered	No. of Tracts Bid On	Acres Bid On	Total Bonus High Bid	No. of Tracts Leased	Acres Leased	Total Bonus Leased Tracts	No. of Bids Rejected	Total Bonus Rejected	Average Per Acre	No. of Bids Rec'd
1	10/13/54	LA	199	748,819	90	394,721	$ 116,378,476	90	394,721	$ 116,378,476		–	$ 294.84	336
1S*	10/13/54	LA	108	523,630	5	25,000	$ 1,233,500	5	25,000	$ 1,233,500		–	$ 49.34	5
2	11/9/54	TX	38	111,789	19	67,149	$ 23,357,029	19	67,149	$ 23,357,029		–	$ 347.84	90
3	7/12/55	TX, LA	210	674,095	121	402,567	$ 108,528,726	121	402,567	$ 108,528,726		–	$ 269.59	384
5	5/26/59	FL	80	458,000	23	132,480	$ 1,711,872	23	132,480	$ 1,711,872		–	$ 12.92	23
6	8/11/59	LA	38	81,813	28	62,967	$ 90,286,693	19	38,820	$ 88,035,120	[illegible]	$ 2,251,573	$ 2,267.28	56
7	2/24/60	TX, LA	385	1,610,254	173	813,663	$ 285,180,648	147	704,526	$ 282,641,815	26	$ 2,538,833	$ 350.46	444
RSA*	5/19/60	LA	10	22,085	1	2,500	$ 75,250	1	2,500	$ 75,250		–	$ 30.10	1
9	3/13/62	LA	401	1,808,276	212	981,407	$ 177,745,105	206	956,407	$ 177,260,305	6	$ 484,800	$ 185.34	538
10	3/16/62	TX, LA	410	1,875,984	210	977,092	$ 268,724,090	205	956,592	$ 268,333,397	5	$ 390,693	$ 280.51	666
11	10/9/62	LA	19	33,855	14	24,858	$ 44,399,399	9	16,178	$ 43,887,359	5	$ 512,040	$ 2,712.79	26
P1	5/14/63	CA	129	669,777	58	312,975	$ 12,807,587	57	312,945	$ 12,807,337	1	$ 250	$ 40.93	70
12	4/28/64	LA	28	34,028	23	32,671	$ 60,340,626	23	32,671	$ 60,340,626	–	–	$ 1,846.90	69
P2	10/1/64	OR, WA	196	1,090,074	101	580,853	$ 35,533,701	101	580,853	$ 35,533,701	–	–	$ 61.18	222
13S	12/14/65	TX	658	947,520	50	72,000	$ 33,740,309	50	72,000	$ 33,740,309	–	–	$ 468.62	113
14	3/29/66	LA	18	35,993	18	35,993	$ 89,054,406	17	35,056	$ 88,845,963	1	$ 208,443	$ 2,534.44	64
15	10/18/66	LA	52	227,898	32	134,717	$ 101,730,216	24	104,717	$ 99,164,930	8	$ 2,565,286	$ 946.98	79
P3	12/15/66	CA	1	1,995	1	1,995	$ 21,189,000	1	1,995	$ 21,189,000	–	–	$ 10,618.50	7
16	6/13/67	LA	206	971,489	172	812,202	$ 511,957,288	158	744,456	$ 510,079,178	14	$ 1,878,110	$ 685.17	743
17SA	9/5/67	LA	8	16,995	1	2,495	$ 30,564	1	2,495	$ 30,564	–	–	$ 12.25	1
P4	2/6/68	CA	110	540,609	75	383,341	$ 603,204,284	71	363,181	$ 602,719,262	4	$ 485,022	$ 1,659.56	164
18	5/21/68	TX	169	728,551	141	666,631	$ 602,475,717	110	541,304	$ 593,899,046	31	$ 8,576,671	$ 1,097.16	556
19	11/19/68	LA	26	46,824	21	40,262	$ 150,482,797	16	29,679	$ 149,868,789	5	$ 614,008	$ 5,049.59	38
19A	1/14/69	LA	38	96,389	26	61,628	$ 45,588,052	20	48,504	$ 44,037,339	6	$ 1,550,713	$ 907.90	40
20S	5/13/69	LA	120	165,605	38	50,880	$ 3,678,045	4	5,625	$ 715,150	34	$ 2,962,895	$ 127.14	43
19B	12/16/69	LA	27	93,764	16	60,153	$ 66,908,196	16	60,153	$ 66,908,196	–	–	$ 1,112.30	58
21	7/21/70	LA	34	73,360	21	50,889	$ 98,101,013	19	44,642	$ 97,769,013	2	$ 332,000	$ 2,190.07	59
22	12/15/70	LA	127	593,485	127	593,485	$ 851,388,599	119	553,898	$ 847,295,760	8	$ 4,092,839	$ 1,529.70	1043
23	11/4/71	LA	18	55,872	13	42,222	$ 96,491,023	11	37,222	$ 96,304,523	2	$ 186,500	$ 2,587.29	33
24	9/12/72	LA	78	366,682	74	346,693	$ 586,297,925	62	290,321	$ 585,827,925	12	$ 470,000	$ 2,017.87	324
25	12/19/72	LA	132	604,029	119	548,374	$ 1,673,054,912	116	535,874	$ 1,665,519,631	3	$ 7,535,281	$ 3,108.04	690
TOTALS			4,073	15,309,539	2,023	8,714,863	$ 6,761,675,048	1,841	8,094,531	$ 6,724,039,091	182	$ 37,635,957		6,985

*S – Sulphur

*SA – Salt

Table H-4

ALL LEASE OFFERINGS (continued)

Lease Offering	Date of Offering	Location	No. of Tracts Offered	Acres Offered	No. of Tracts Bid On	Acres Bid On	Total Bonus High Bid	No. of Tracts Leased	Acres Leased	Total Bonus Leased Tracts	No. of Bids Rejected	Total Bonus Rejected	Average Per Acre	No. of Bids Rec'd.
TOTALS BROUGHT FWD			4,073	15,309,539	2,023	8,714,863	$ 6,761,675,048	1,841	8,094,531	$ 6,724,039,091	182	$ 37,635,957		6,985
26	6/19/73	TX, LA	129	697,643	104	566,573	$ 1,598,590,620	100	547,173	$ 1,591,397,380	4	$ 7,193,240	$ 2,908.40	551
32	12/20/73	MAFLA	147	817,297	89	496,917	$ 1,491,617,119	87	485,397	$ 1,491,065,231	2	$ 551,888	$ 3,071.85	373
33	3/28/74	LA	206	930,918	114	522,397	$ 2,175,095,514	91	421,218	$ 2,092,510,854	23	$ 82,584,660	$ 4,967.76	402
34	5/29/74	TX	245	1,355,678	123	680,335	$ 1,502,429,426	102	565,112	$ 1,471,851,831	21	$ 30,577,595	$ 2,604.53	352
51	7/30/74	TX, LA	258	1,278,739	49	249,704	$ 76,617,645	19	100,241	$ 30,236,800	30	$ 46,380,845	$ 301.64	57
36	10/16/74	LA	287	1,370,031	149	693,172	$ 1,444,156,465	136	634,832	$ 1,427,242,455	13	$ 16,914,010	$ 2,248.22	330
	10/16/74	LA-ROY	10	51,515	8	40,755	$ 1,018,875	8	40,755	$ 1,018,875	–	–	$ 25.00	57
37	2/4/75	TX	515	2,870,344	143	796,367	$ 300,632,667	113	626,585	$ 274,690,955	30	$ 25,941,712	$ 438.39	281
38	5/28/75	TX, LA	283	1,346,437	102	486,327	$ 250,681,156	86	406,942	$ 232,916,050	16	$ 17,765,106	$ 572.36	191
38A	7/29/75	TX, LA	345	1,772,958	80	408,009	$ 171,511,620	66	336,301	$ 163,214,006	14	$ 8,297,614	$ 485.32	179
35	12/11/75	CA	231	1,257,593	70	384,540	$ 438,190,780	56	310,049	$ 417,312,141	14	$ 20,878,639	$ 1,345.96	166
41	2/18/76	GOM	132	687,604	41	191,718	$ 183,498,244	34	161,286	$ 175,976,493	7	$ 7,521,751	$ 1,091.09	81
39	4/13/76	GOA	189	1,008,500	81	437,524	$ 571,871,587	76	409,058	$ 559,836,587	5	$ 12,035,000	$ 1,368.60	244
40	8/17/76	Mid-ATL	154	876,750	101	575,012	$ 1,135,802,179	93	529,466	$ 1,127,936,425	8	$ 7,865,754	$ 2,130.33	410
44	11/16/76	TX, LA	61	254,488	48	201,825	$ 381,911,757	43	178,127	$ 379,148,962	5	$ 2,762,795	$ 2,128.53	117
47	6/23/77	GOM	223	1,074,536	152	739,326	$ 1,214,002,429	124	605,427	$ 1,170,093,432	28	$ 43,908,997	$ 1,932.68	424
C1	10/27/77	Lo. C1	135	768,580	91	518,080	$ 400,319,543	87	495,307	$ 398,471,313	4	$ 1,848,230	$ 804.49	240
43	3/28/78	So. ATL	224	1,275,273	57	324,511	$ 109,695,692	43	244,807	$ 100,743,443	14	$ 8,952,249	$ 411.52	99
45	4/25/78	TX, LA	145	709,727	101	490,752	$ 767,407,369	90	438,756	$ 733,656,893	11	$ 33,750,476	$ 1,672.13	283
65	10/31/78	GOM	89	511,709	35	201,295	$ 61,176,730	35	201,295	$ 61,176,730	–	–	$ 303.92	62
51	12/19/78	TX, LA	128	643,987	88	449,691	$ 884,589,799	81	412,416	$ 871,464,998	7	$ 13,124,801	$ 2,113.07	288
49	2/28/79	Mid-ATL	109	620,557	44	250,500	$ 41,720,618	39	222,034	$ 40,001,631	5	$ 1,718,987	$ 180.16	74
48	6/29/79	CA	148	792,845	55	294,018	$ 573,956,402	54	288,260	$ 572,825,418	1	$ 1,130,984	$ 1,987.18	112
58	7/31/79	GOM	123	577,517	88	424,030	$ 1,261,358,089	81	391,183	$ 1,247,489,022	7	$ 13,869,067	$ 3,189.02	316
58A	11/27/79	GOM	124	588,601	96	450,914	$ 1,932,894,290	90	421,519	$ 1,913,337,938	6	$ 19,556,352	$ 4,539.15	322
BF	12/11/79	Beau. Sea	46	172,320	25	88,037	$ 491,728,138	24	85,776	$ 488,691,137	1	$ 3,037,001	$ 5,799.68	62
42	12/18/79	No. ATL	116	660,409	73	415,602	$ 827,832,854	63	358,671	$ 816,516,546	10	$ 11,316,308	$ 2,276.51	189
TOTALS			8,875	40,302,090	4,230	20,092,794	$ 27,051,982,655	3,762	18,012,524	$ 26,574,862,637	468	$ 477,120,018		13,247

Table H-4

ALL LEASE OFFERINGS (continued)

Lease Offering	Date of Offering	Location	No. of Tracts Offered	Acres Offered	No. of Tracts Bid On	Acres Bid On	Total Bonus High Bid	No. of Tracts Leased	Acres Leased	Total Bonus Leased Tracts	No. of Bids Rejected	Total Bonus Rejected	Average Per Acre	No. of Bids Rec'd
TOTALS BROUGHT FWD			8,875	40,302,090	4,230	20,092,794	$ 27,051,982,655	3,762	18,012,524	$ 26,574,862,637	468	$ 477,120,018	$ 6,387.82	13,247
A62	9/30/80	GOM	192	909,575	147	706,042	$ 2,805,524,393	116	551,654	$ 2,676,927,673	31	$ 128,596,720	$ 4,852.54	506
55	10/21/80	GOA	210	1,195,569	37	210,648	$ 117,550,113	35	199,261	$ 109,751,073	2	$ 7,799,040	$ 550.79	64
62	11/18/80	GOM	81	458,308	74	420,058	$ 1,436,448,959	67	383,323	$ 1,417,961,511	9	$ 18,487,448	$ 3,699.12	268
53	5/28/81	CA	111	603,613	81	432,815	$ 2,277,856,761	60	320,579	$ 2,047,800,089*	21	$ 24,648,000	$ 6,387.82	301
RS1	6/30/81	AK	175	996,308	5	28,466	$ 3,091,738	1	5,694	$ 170,496	4	$ 2,921,242	$ 29.95	7
A66	7/21/81	GOM	212	1,077,931	162	829,900	$ 2,666,828,352	156	799,912	$ 2,649,628,752	6	$ 17,199,600	$ 3,312.40	419
56	8/4/81	So. ATL	285	1,621,901	54	307,308	$ 363,829,954	47	267,471	$ 342,766,174	7	$ 21,063,780	$ 1,218.51	120
60	9/29/81	Lo. C1	153	858,247	13	73,158	$ 4,405,899	13	73,158	$ 4,405,899	–	$ –	$ 60.22	15
66	10/20/81	GOM	209	1,081,364	107	532,064	$ 1,280,983,917	102	508,301	$ 1,243,468,752	5	$ 37,515,165	$ 2,446.32	233
59	12/8/81	Mid-ATL	253	1,440,376	98	557,932	$ 424,927,000	51	290,352	$ 232,659,000	47	$ 101,268,000	$ 1,114.71	240
67	2/9/82	GOM	234	1,219,847	137	695,765	$ 1,251,793,459	115	590,265	$ 1,193,654,719	22	$ 58,138,740	$ 2,022.29	290
68	6/11/82	S. CA	140	716,866	35	176,253	$ 132,252,632	29	147,066	$ 117,875,281	6	$ 14,377,351	$ 668.77	66
RS2	8/5/82	ATL,CA,AK	554	3,142,069	40	227,727	$ 12,310,706	36	204,955	$ 11,149,450	4	$ 1,161,256	$ 54.40	48
71	10/13/82	AK-DF	338	1,825,770	125	683,026	$ 2,067,604,786	121	662,861	$ 2,055,632,336	4	$ 11,972,450	$ 3,101.00	252
69(1)	11/17/82	GOM	144	732,570	67	339,999	$ 634,919,980	56	281,213	$ 609,178,223	11	$ 25,741,757	$ 2,166.24	151
69(2)	3/8/83	GOM	125	665,478	13	68,106	$ 39,741,340	11	58,120	$ 37,570,900	2	$ 2,170,440	$ 646.44	20
57	3/15/83	AK-NB	418	2,379,751	64	364,364	$ 325,267,372	59	335,898	$ 317,873,372	5	$ 7,394,000	$ 946.34	98
70	4/12/83	AK-SG	479	2,688,787	97	552,239	$ 427,343,830	96	546,546	$ 426,458,830	1	$ 885,000	$ 780.28	150
76	4/26/83	Mid-ATL	4,050	22,664,991	40	227,727	$ 71,141,240	37	210,641	$ 68,410,240	3	$ 2,731,000	$ 324.77	53
72	5/25/83	CGOM	7,050	37,867,762	656	3,249,199	$ 3,469,214,969	623	3,089,872	$ 3,367,606,134	33	$ 101,608,835	$ 1,089.89	1,015
TOTALS			24,288	124,449,173	6,282	30,775,590	$ 46,865,020,055	5,593	27,539,666	$ 45,505,811,541	691	$ 1,062,799,842		17,563

* The 1/5th bonuses (totaling $43,081,734) on 12 leases were forfeited by the companies May, 1984. Amount not included in Total Bonus figure.

Table H-4

ALL LEASE OFFERINGS (continued)

Lease Offering	Date of Offering	Location	No. of Tracts Offered	Acres Offered	No. of Tracts Bid On	Acres Bid On	Total Bonus High Bid	No. of Tracts Leased	Acres Leased	Total Bonus Leased Tracts	No. of Bids Rejected	Total Bonus Rejected	Average Per Acre	No. of Bids Rec'd.
TOTALS BROUGHT FWD.			24,288	124,449,173	6,282	30,775,590	$ 46,865,020,055	5,593	27,539,666	$ 45,508,811,541	691	$ 1,062,799,842		17,563
78	7/26/83	So-ATL	3,582	20,156,426	11	62,625	$ 13,362,060	11	62,625	$ 13,362,060	0	$ 0	$ 213.37	12
79	8/24/83	WGOM	5,848	32,620,248	436	2,410,809	$ 1,549,262,300	406	2,246,005	$ 1,501,712,517	30[1]	$ 47,549,783[1]	$ 668.28	775
80	11/30/83	S CA	137	1,898,571	8	43,801	$ 16,022,336	8	43,801	$ 16,022,336	0	$ 0	$ 365.82	14
81	12/13/83	EGOM	8,848	50,631,513	156	897,786	$ 310,586,261	156	897,786	$ 310,586,261	0	$ 0	$ 345.95	226
82	4/17/84	New Bed	5,036	28,048,995	186	1,058,922	$ 631,228,331	180	1,024,772	$ 624,491,331[1]	6	$ 6,737,000	$ 609.40	425
83	4/24/84	CGOM	6,502	34,743,780	529	2,650,128	$ 1,446,584,927	453	2,278,179	$ 1,323,036,649	76	$ 123,548,278	$ 580.74	793
84	7/18/84	WGOM	5,466	30,038,593	402	2,173,724	$ 945,717,312	361	1,949,213	$ 844,850,488	41	$ 100,866,824	$ 433.43	593
85	8/22/84	Deepw	1,475	7,773,447	232	1,233,573	$ 871,131,327	227	1,230,486	$ 871,964,327[1]	1	$ 5,167,000	$ 722.00	432
86	10/17/84	S CA	657	3,147,352	25	125,100	$ 66,231,426	23	114,367	$ 62,121,252	2	$ 4,110,174	$ 543.17	30
87	5/22/85	CGOM	4,531	24,006,157	444	2,241,596	$ 1,147,434,447	409	2,076,943	$ 1,079,377,760	35	$ 68,056,687	$ 519.69	444
88	8/14/85	WGOM	4,879	27,199,074	210	1,156,841	$ 391,137,536							265
TOTALS			71,249	384,713,329	8,921	44,830,507	$ 54,259,718,298	7,827	39,463,843	$ 52,156,336,502	882	$ 1,418,835,588		21,770

Highest Per-Acre Bid-Lease Offering $3,565,014.16
Total Amount of All Bids Received for All Lease Offerings-$118,972,214,925
Total Amount of All Rentals for All Lease Offerings-$121,982,060

[1] In two cases (OCS-G 6240 and OCS-G 6257), the lease forms were not executed by the high bidder(s) within the time allowed, resulting in forfeiture of the one-fifth bonus deposit and their right to acquire the leases.
[2] Four tracts amounting to $5,104,000.00 included in this figure are in dispute and leases have not been issued.
[3] Seventeen tracts amounting to $108,174,000 included in this figure are in dispute and leases have not been issued.

V. Relevant Environmental and Predictive Information

Section 18(a)(2)(H) of the OCS Lands Act, as amended, requires the Secretary to consider relevant environmental and predictive information in determining the timing and location of exploration, development, and production activities among the physiographic OCS regions. This consideration cannot be isolated from other considerations required by section 18(a)(2), especially subparts (A), (D), and (G). Analysis based on the requirements in subparts (A), (D), and (G), as well as other requirements, are included in the SID.

Much of the available, relevant environmental information on the OCS planning areas has been developed through the Department of the Interior's OCS Environmental Studies Program. The studies program was initiated in 1973 and was administered by the Bureau of Land Management until 1982. In 1982 administration of the program was transferred to the Minerals Management Service. Since its inception, the OCS Environmental Studies Program has invested more than $370 million in oceanographic and socioeconomic studies. In Fiscal Year 1983, the OCS Environmental Studies Program provided 95 percent of all Federal funds for ocean pollution research related to offshore oil and gas activities (Interagency Committee on Ocean Pollution Research, Development, and Monitoring [COPRDM], 1984).

Since its inception, the OCS Environmental Studies Program has supported studies in almost all of the planning areas. The environmental studies program funding through Fiscal Year 1984 by planning area is summarized in Table H-5.

The OCS Environmental Studies Program is currently supporting numerous studies designed to increase and improve information which supports accurate prediction of the effects of OCS activities. These studies include monitoring of actual exploration and development operations and their effects on whales and marine mammals, benthic communities, and fish populations. The studies focus on the effect of spilled oil, drilling discharges, and noise generated from OCS activities. The studies program is also sponsoring some laboratory toxicity assessments. When it began, the studies program sponsored many large baseline studies in the OCS planning areas. The program's emphasis on this type of study has declined and it currently supports very few of these studies. The few remaining baseline studies are being conducted in Alaska and in deepwater areas in the Atlantic and Gulf of Mexico. The program's support of these studies will probably end within the next 2 to 3 years.

In addition to the environmental studies, the Department of the Interior has produced environmental impact statements (EIS) on the potential consequences of OCS oil and gas activities in almost every OCS Planning area. The number of EIS's written for each planning area is listed in Table H-6. An oil spill trajectory analysis is normally prepared for each EIS. The number of these analysis produced for lease sales in the various OCS planning areas is also listed in Table H-6.

TABLE H-5

Environmental Studies Program Funding Through Fiscal Year 1984
by Planning Area

Planning Area	Total for Planning Area /1	Studies Exclusive to Planning Area/2
North Atlantic	$47,746,324	$28,627,801
Mid-Atlantic	30,660,147	11,522,374
South Atlantic	30,628,384	21,303,475
Straits of Florida	0	0
Eastern Gulf	32,209,276	4,688,827
Central Gulf	36,695,813	3,126,745
Western Gulf	30,494,831	9,897,446
Southern California	30,297,734	17,906,916
Central California	22,815,267	4,248,151
Northern California	15,857,298	1,352,075
Washington-Oregon	1,495,577	190,877
Gulf of Alaska	49,948,724	8,240,292
Kodiak	55,829,130	3,437,657
Shumagin	1,800,607	0
Cook Inlet	41,807,473	2,582,477
North Aleutian Basin	71,887,025	3,697,414
St. George Basin	67,629,206	782,068
Navarin Basin	48,782,555	2,525,061
Norton Basin	72,812,927	3,862,320
Hope Basin	22,884,659	0
Chukchi Sea	91,930,007	6,787,407
Beaufort Sea	88,631,551	7,685,693

/1 Summing these numbers will result in a number significantly higher than the total ESP spending because some studies are included in more than 1 planning area

/2 Summing these numbers will result in a lower than the total ESP spending because generic studies are not included.

TABLE H-6

Number of Lease Sale-Specific Environmental Impact Statements (EIS)
and Oil Spill Risk Analyses (OSRA) Prepared for each
Planning areas Through January 1985

Planning Areas	Number of EIS's	Number of OSRA's
North Atlantic	3	3
Mid-Atlantic	5	5
South Atlantic	4	4
Straits of Florida	0	0
Eastern Gulf of Mexico	12	4
Central Gulf of Mexico	19	4
Western Gulf of Mexico	18	4
Southern California	4	3
Central California	2	2
Northern California	1	1
Washington-Oregon	0	0
Gulf of Alaska	3	2
Cook Inlet	3	2
Kodiak	1	1
Shumagin	0	0
North Aleutian Basin	1	1
St. George Basin	2	2
Navarin Basin	1	1
Norton Basin	2	2
Hope Basin	0	0
Chukchi Sea	0	1
Beaufort Sea	3	2

The EIS's and the oil spill trajectory analyses, air quality analyses, cultural resource analyses, and socioeconomic analyses included in them are all supported, in part, by the OCS Environmental Studies Program. Each of the analyses listed above represents a use of studies information and a refinement of that information for relevant leasing and lease management issues. The EIS, which is required for OCS lease sales under the National Environmental Policy Act (NEPA), is a point at which these analyses and others are joined in a broad assessment of the impacts of the OCS oil and gas activities in planning areas. The EIS's contain both area-specific and generic analyses. As required under NEPA and its implementing regulations, the lease sale EIS focuses large amounts of information on relevant issues.

In addition to depending upon Environmental Studies Program information, EIS's also contain relevant information generated by other parties. Although the studies program provides most new information directly relevant to OCS issues, other programs also provide useful information. Among these programs are the whale and marine mammals programs and the fisheries programs of the National Marine Fisheries Service, oceanographic data collection programs of the National Oceanic and Atmospheric Administration, and toxicity and effects studies of the Environmental Protection Agency.

Through the EIS process, decisionmakers are provided with an additional means of focusing attention on relevant information. That mechanism includes scoping for and public review and comment on the EIS. These procedures, which are required by NEPA, insure public review of information used in the decisionmaking process. Public comments on EIS's focus on the information used and the adequacy of the subsequent analyses, thus providing the Secretary with another source of relevant environmental and predictive information. The information provided by the public is used to develop and revise EIS's, to prepare decision material, and to design additional studies to support leasing and lease management decisions.

Appendix I

RELATIVE MARINE PRODUCTIVITY AND ENVIRONMENTAL SENSITIVITY

RELATIVE MARINE PRODUCTIVITY AND ENVIRONMENTAL SENSITIVITY

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RELATIVE MARINE PRODUCTIVITY AND ENVIRONMENTAL SENSITIVITY

I. Introduction

Section 18(a)(2)(G) of the OCS Lands Act, as amended, requires that the Secretary of the Interior consider the relative marine productivity and environmental sensitivity of the various oil and gas bearing physiographic regions of the OCS in determining the timing and location of oil and gas activities. Analyses of relative marine productivity and environmental sensitivity were conducted to aid in the development of the 1982 OCS leasing schedule (Part II.B and Appendix 10 of the SID for the 1982 program). Those analyses demonstrated the complexity of collecting, analyzing, and interpreting scientific information to satisfy the requirements of section 18(a)(2)(G). In spite of the difficulties described in the 1982 analyses, the approaches to those analyses were upheld as reasonable by the U.S. Court of Appeals for the District of Columbia on July 5, 1983.

In preparation for current analyses, analytical approaches were discussed with the OCS Advisory Board Policy Committee (October 1984) and Scientific Committee (November 1984). The present analysis incorporates some of the advice and guidance received. Some of the suggestions from these advisory groups were more appropriate to environmental analyses which will follow the present analyses. These suggestions will be considered during the preparation of the environmental impact statement (EIS) for the proposed program and in subsequent sale-specific EIS's. Almost all parties who provided advice agreed that both the productivity and sensitivity analyses required by section 18(a)(2)(G) are complex and difficult. In addition to this advice, the Department has received or developed more information on the habitats and biota of the OCS than was available in 1982. The principal mechanism for the Department to develop such information is the OCS Environmental Studies Program administered by the Minerals Management Service.

II. Relative Marine Productivity

The term "productivity" has a distinct meaning to marine biologists. It means the "primary productivity" of marine plants. Primary productivity is the amount of plant tissue produced through photosynthetic fixation of carbon during a standard period of time. Both phytoplankton, microscopic marine plants, and fixed or rooted plants contribute to the primary productivity of most OCS planning areas. However, phytoplankton are the most important primary producers because of their large numbers and their wide distribution. Rooted or fixed plants are generally confined to the shallow portions of the planning areas. Phytoplankton can occupy all surface waters of a planning area and can fix carbon as long as sufficient light and nutrients are available. Riley (1970) estimated the normal range of marine primary productivity to be between 50 and 150 grams of carbon per square meter of ocean surface per year. Productivity in inshore areas and areas of upwelling can be as much as ten times greater than oceanic productivity.

A. Methods

The primary productivity of phytoplankton was used to rank the various planning areas in the 1982 analysis of relative marine productivity. Measurements of phytoplankton productivity have been made in almost all of the planning areas. The methods for measuring phytoplankton productivity are relatively standard. Most of the data used in the present analysis, except that provided by Smith and Kalber (1974), is based on ^{14}C assimilation measurements of phytoplankton productivity. Results of phytoplankton productivity studies are expressed in terms of the amount of carbon fixed during photosynthesis per unit area in a specified time. The figures used in the present analysis are expressed as grams of carbon fixed per square meter per year ($gC/m^2/yr$). By using a period of one year for reporting primary productivity, periods of extremely high or low productivity are incorporated in their appropriate importance in terms of their contribution to the annual productivity. This is especially important in areas where productivity is highly seasonal.

The 1982 analysis of marine productivity relied upon the "Estimation of organic production in the oceans" (Figure 1.1-5) presented by Smith and Kalber (1974). The productivity ranges provided in that undocumented map were used to rank the OCS planning areas in 1982. For the current analysis, the estimates of Smith and Kalber (1974) were compared with more current estimates based upon documented measurements. These measurements are reported in many Department of the Interior EIS's for OCS oil and gas lease sales, reports from the OCS Environmental Studies Program, and other available literature (Table I-1). The productivity ranges provided by Smith and Kalber (1974) were generally supported by the more recent data.

A major difference between the 1982 analysis and the present analysis is the productivity attributed to the North Aleutian Basin and the St. George Basin, Alaska. Smith and Kalber (1974) estimated the annual productivity to range from 400 to 7300 gC/m^2. The upper value of this range is equivalent to an average daily productivity of 20 gC/m^2. This high value is twice the high productivity rate reported for phytoplankton blooms in the area by Goering and McRoy (1981). Alexander and Cooney (1978) observed that approximately 65% of annual primary production on the Bering Sea shelf occurs in blooms between April and June. Niebauer, Alexander, and Cooney (1981) measured peak productivities of 25 gC/m^3/hour along the ice edge in the southeastern Bering Sea. They noted that these productivity peaks normally occur during late May and persist for about two weeks. The area of peak productivity occurs within 40 to 80 km of the ice edge. As a result of these documented observations, the present analysis includes an estimate of annual primary production for the North Aleutian Basin and St. George Basin of 400 $gC/m^2/yr$ provided by Goering and McRoy (1981). This value of appears more reasonable than the range provided by Smith and Kalber (1974). The use of the summary provided by Smith and Kalber (1974) without verification of the figures for the North Aleutian Basin and the St. George Basin skewed the conclusions of the 1982 productivity analysis. The present analysis corrects that error.

Phytoplankton productivity can vary more significantly within a planning area than between planning areas. For example, O'Reilley and Busch (1984)

TABLE I-1

Marine Phytoplankton Productivity by Planning Area
Expressed as Grams of Carbon Fixed per Square Meter per Year

Planning Area	Range of Values Used in the 1982 Analysis ($gC/m^2/yr$)*	More Recent Observations ($gC/m^2/yr$)	Reference
North Atlantic	200-400	230-470	O'Reilly & Busch (1984)
Mid-Atlantic	200-400	260-370	O'Reilly & Busch (1984)
South Atlantic	50-200	130-360	Haines & Dunstan (1975)
			Yoder et al. (1983)
Straits of Florida	50-100		
Eastern Gulf of Mexico	50-100	10-110	UMES (1985)
Central Gulf of Mexico	50-100	10-220	El-Sayed & Turner (1977)
Western Gulf of Mexico	50-100	15-70	El-Sayed & Turner (1977)
Southern California	200-400	180-360	Eppley et al. (1979)
Central California	200-400	10-470	Riznyk (1977)
Northern California	200-400	10-470	Riznyk (1977)
Washington/Oregon	200-400	35-350	Small et al. (1972)
Gulf of Alaska	200-400		
Cook Inlet	200-400		
Kodiak	200-400		Griffiths et al. (1982)
Shumagin	200-400		
North Aleutian Basin	400-7300	120-400	Goering & McRoy (1981)
St. George Basin	400-7300		
Navarin Basin	50-200		
Norton Basin	50-100		
Hope Basin	<50		
Chukchi Sea	<50	18-28	Carey (1978)
Beaufort Sea	<50	10-20	Schell & Horner (1981)

* Data from Smith and Kalber(1974)

reported that productivity in the shallow areas of Georges Bank (North Atlantic) averaged 470 $gC/m^2/yr$ while in deeper waters landward of the shelf break, productivity averaged 370 $gC/m^2/yr$. Productivity in the deeper waters of the North Atlantic averaged 230 $gC/m^2/yr$. Determining an appropriate range or average productivity rate for the North Atlantic or any other planning area requires careful attention to the temporal and spatial significance of reported observations.

Even with the addition of new information, ranking the OCS planning areas by their relative marine productivity is difficult. The ranges of observed production are broad and overlap. The ranges do not provide an average or other measure of central tendency or the frequency of the observations. Ranges are not amenable to statistical comparison, and comparisons among them are tenuous at best. However, the new information appears to support the principal results of the 1982 analysis.

B. Results

In the 1982 analysis, the planning areas were grouped into four productivity classes: highest, next-to-highest, next-to-lowest, and lowest. The North Aleutian Basin and the St. George Basin were the only planning areas in the "highest" class. Based upon the data of Goering and McRoy (1981), the average annual productivity of these planning areas is substantially lower than the values reported by Smith and Kalber (1974). As a result of the lowering of the productivity ranges for the North Aleutian and St. George Basins, only three productivity classes (high, moderate, and low) are distinguished in the present analysis (Table I-2). The placement of a planning area into any of the productivity classes in Table I-2 is based on the ranges reported in Table I-1 and on information on the appropriate areal mean productivity which may be provided by the references included in Table I-1.

Twelve planning areas are included in the "high productivity" class. Further differentiation within this group must await more precise definition of the appropriate ranges or other statistical description. The principal difference between the present analysis and the 1982 analysis is the elimination of the "highest" productivity class from the 1982 analysis and the inclusion of the North Aleutian Basin and the St. George Basin into the "high" productivity class of the present analysis.

In the present analysis, the planning areas designated as having "moderate" productivity are those with reported observations ranging from 50 to 200 $gC/m^2/yr$. Seven planning areas occur in this class.

Finally, the three planning areas in the Arctic (Hope Basin, Chukchi Sea, and Beaufort Sea) are the least productive of the OCS planning areas. Information from Carey (1978) and Schell and Horner (1981) confirms the low productivity in two of these areas.

C. Additional Measures of Marine Productivity

The phytoplankton productivity data discussed in the present analysis are some of the most consistently expressed data in biological oceanography.

TABLE I-2

Relative Phytoplankton Productivity of the OCS Planning Areas
Expressed as Grams of Carbon Fixed per Square Meter per Year

High Productivity (200 to 500 $gC/m^2/yr$)

North Atlantic
Mid-Atlantic
North Aleutian Basin
St. George Basin
Southern California
Central California
Northern California
Washington and Oregon
Gulf of Alaska
Cook Inlet
Kodiak
Shumagin

Moderate Productivity (50 to 200 $gC/m^2/yr$)

South Atlantic
Straits of Florida
Eastern Gulf of Mexico
Central Gulf of Mexico
Western Gulf of Mexico
Navarin Basin
Norton Basin

Low Productivity (<50 $gC/m^2/yr$)

Hope Basin
Chukchi Sea
Beaufort Sea

Even so, comparisons among observed productivities are tenuous for the reasons described in the preceding discussion. The problems associated with attempting to use other biota to assess marine productivity are illustrated in Table 6 of the 1982 analysis. Even with the additional data collected since 1982, available information is not sufficient to support a rigorous evaluation of the relative abundance of various organisms in the OCS planning areas. In many instances, quantitative information on some biota is unavailable, while for others, the development of "planning-area representative" information is not practical.

However, information on the relative abundance of eight additional categories of biota was compiled, reviewed, and used in the matrix exemplified in Table I-3 to complete the environmental sensitivity analysis. Available information on standing stocks and distributions was used to determine whether the "abundance" of the biota in a planning area relative to all other planning areas is high, moderate, or low. Making such determinations generally required extrapolations of existing data and simplifying assumptions. Some of these extrapolations and assumptions are described in the following sections.

III. Relative Environmental Sensitivity

The concept of environmental sensitivity is even more complex than the concept of marine productivity. The 1982 analysis clearly demonstrated this complexity. Simplifying assumptions and scientific judgments were used in the 1982 analysis to develop a strategy to measure environmental sensitivity. The present analysis contains some of those assumptions and judgments. However, in many instances the assumptions and judgments have been replaced by information that was not available in 1982.

The 1982 analysis of environmental sensitivity was based, in large part, on an evaluation of the sensitivity of various coastal and marine habitats and biota to spilled crude oil. Limiting the analysis to spilled crude oil provided the following advantages:

1. Different areas of the OCS could be evaluated against a common factor, in this case, spilled crude oil.
2. Effects from overlapping factors could be avoided.
3. Oil spills, although rare, would cause the largest, most visible, and measurable effects of OCS activities.

The present analysis of environmental sensitivity also concentrates on the effects of spilled oil. However, some other factors were also evaluated in Appendix I-2 of the draft proposed program. These evaluations are not repeated in the proposed program but are available for review (see section IV.C of this appendix). These factors include the following:

1. Operational discharges from OCS activities (drilling muds, cuttings, and formation waters).
2. Noise generated by OCS activities.
3. Habitat alteration from the installation of OCS facilities.
4. Air emissions from OCS operations.

TABLE I-3

Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: Hypothetical

Overall Total Score: 290

	Distribution of Resource (1)	(2)	Sensitivity Coefficient (3)	(4)	Score (5)
Coastal Habitats	Miles				
Estuaries/Wetlands	200	33	High	225	74.25
Sandy Beaches	300	50	Low	45	22.50
Rocky Beaches	100	17	Moderate	135	22.95
TOTAL	600				119.70
Marine Habitats	Acres				
Submerged Vegetation	1,200,000	5.3	Moderate	135	7.16
Submarine Canyons	None	0.0	Low	45	0.00
Coral Reefs	5,000	0.02	High	225	0.05
Hard Bottoms	600,000	2.6	Low	45	1.17
Shelf Break Zone	850,000	3.7	Low	45	1.67
Mud/Sand Bottom	20,000,000	88.2	Low	45	39.69
TOTAL	22,655,000				49.74
Biota					
Phytoplankton	High	5	Low	1	5
Juvenile Fish/Shellfish	High	5	High	5	25
Adult Fish/Shellfish	Moderate	3	Moderate	3	15
Mud/Sand Benthos	Low	1	Low	1	1
Coastal Birds	Moderate	3	High	5	15
Marine Birds	High	5	High	5	25
Marine Turtles	None	0	Low	1	0
Marine Mammals	High	5	High	5	25
Whales	Moderate	3	High	5	15
TOTAL					120

(1) Linear or areal extent of habitat; abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.

These factors are not included in the calculations because of the difficulty of measuring their effects on the same basis as the effects of oil spills. In addition, information on the effects of some of these factors on habitats and biota throughout the entire OCS is not available. The effects of operational discharges, noise, habitat alteration, and air emissions will be considered further in other environmental analyses done of the 5-Year Program, such as the EIS on the proposed program, and in subsequent sale-specific EIS's. While the cumulative effects of these four factors may be more extensive and long lasting than the effects of a large oil spill, the Department of the Interior and other Federal, State, and local agencies have means available to control some of the adverse effects of these factors.

A. Methods

For the purposes of the calculations for the present analysis (Table I-3 and Appendix I-1), environmental sensitivity is defined in terms of the following variables:

1. the severity of damage resulting from the contact of spilled oil with various coastal and marine habitats and biota (this was designated as the persistence of oil in the 1982 analysis), and

2. the time required for the habitat or population to recover from the effects of contact with spilled oil.

The following assumptions are also included in the present environmental sensitivity analysis:

1. Spilled oil has not weathered significantly when it contacts the habitat or population. Weathering is the transformation of spilled oil through physical, chemical, or biological processes. Physical and chemical processes commence immediately after the spill. These processes include evaporation, spreading, emulsification, solution, and sedimentation. Evaporation is the predominant weathering process in the early stages of an oil spill. Many of the lighter molecular weight, toxic hydrocarbons evaporate from spilled oil within hours of a spill. Other weathering processes disperse the mass of the spilled oil and reduce its concentration. The impacts of spilled oil are reduced significantly by the effects of weathering. By eliminating the mitigating effects of weathering in the analysis of environmental sensitivity, the adverse effects of spilled oil, both toxicity and coating, are maximized. This assumption is conservative and provides an assessment of the most severe effects of spilled oil. However, use of this conservative assumption eliminates consideration of the distance between sensitive resources and potential oil fields or transportation routes. It also eliminates consideration of the mitigating effects of weathering on spilled oil moving from the site of production or transportation to the sensitive resource.

2. All of the biological populations in a planning area are contacted by spilled oil. Migratory species, which may inhabit the planning area for only a short period, are assumed to be present and contacted by spilled oil. Resources with seasonal sensitivities are

assumed to be in their most sensitive stage when they are contacted by spilled oil. This assumption is extremely conservative and provides an assessment of the highest sensitivity of each resource and each planning area as a whole.

Performing an accurate analysis of environmental sensitivity requires a substantial amount of information on the spatial and temporal distribution of resources and the variations in their sensitivities to spilled oil. This is especially true where seasonal phenomena such as changes in productivity or the presence of migratory species would significantly increase or decrease the overall sensitivity of a planning area. If sufficient data were avialable, the overall environmental sensitivity of a planning area would be the sum of the sensitivities of its components integrated over time. This concept was reviewed during the preparation of the present analysis. It was abandoned because the minimum necessary information to conduct such an analysis is not available. Some information on some resources in some planning areas is avaiable, but the data are neither consistent nor available for all planning areas. As a result, the present analysis contains the simplifying assumptions described above. If adequate information were available, it would be possible to develop both expected and worst-case sensitivities. The reliance of the present analysis on conservative assumptions is, nonetheless, appropriate for the purpose of comparing the relative environmental sensitivities of the OCS planning areas.

B. Results

The resource-specific sensitivity evaluation is based on existing information provided in the draft proposed program. This required considerable professional judgment in interpreting the information and drawing conclusions to perform the relative rankings. As a result of this evaluation, the resource-specific sensitivity may differ in the different OCS regions. Where this occurs, this change results from differences in the estimated severity of the impact of spilled oil or in the estimated recovery time of the resource in response to differences in temperature, water depth, or other factors. As an example, in the present analysis, the environmental sensitivity of wetlands decreases from the colder planning areas to the warmer planning areas on the assumptions that oil would persist longer and that wetlands would require a longer period of time to recover in the colder planning areas. Estuaries and wetlands are rated moderately sensitive to spilled oil in the South Atlantic, the Straits of Florida, the Gulf of Mexico, and Southern California. In all other areas, estuaries and wetlands are given a rating of high sensitivity to spilled oil. The sensitivity rating for rocky beaches also changes as it is applied to the various OCS planning areas. In the Arctic (Hope Basin, Chukchi Sea, Beaufort Sea) planning areas, rocky beaches are given a low sensitivity. In most other areas, rocky beaches are given a moderate sensitivity. Sandy beaches are rated as having a low sensitivity in all planning areas.

Based upon the analyses of COPRDM (1981) and NRC (1985) most marine habitats are not very sensitive to spilled oil. These habitats are generally too deep to receive large quantities of oil from the ocean's surface. Most observations of the effects of oil spills have been directed to coastal habitats and biota. As a result, very little information is available on the effects of spilled oil on marine benthic habitats. The principal areas of

sensitivity are shallow habitats such as beds of aquatic vegetation and coral reefs. Live hard bottom habitats may be sensitive in shallow areas. Unfortunately, information on the areal and depth distribution of these habitats is not available for most OCS planning areas.

For biota, the following categories were judged to have a high sensitivity to spilled oil: juvenile fish and shellfish, coastal and marine birds, marine mammals, and whales.

IV. Relative Marine Productivity/Environmental Sensitivity

In the present analysis, the distributions and environmental sensitivities of the three ecological components within and/or on the adjacent coast of each OCS planning area are evaluated. These three components are coastal habitats, marine habitats, and biota. Coastal habitats include estuaries, wetlands, sandy beaches, and rocky beaches. The category of estuaries and wetlands includes lagoons and mangrove or forested wetlands. Marine habitats include submerged aquatic vegetation, coral reefs, live hard bottoms, submarine canyons, mud/sand bottoms, and the shelf break zone. Biota include phytoplankton, juvenile fish and shellfish, adult fish and shellfish, benthic communities of mud/sand bottoms, marine and coastal birds, marine turtles, marine mammals, and whales. The 1982 analysis included an extensive breakdown of fishery resources based on their commercial or subsistence use. This breakdown is not used in the present analysis because it does not add information about environmental sensitivity, only about the social value of the species. Table I-3 is an example of the calculations performed for each of the three ecological components. The calculations for each planning area are included in Appendix I-1.

A. Methods

Calculation of the overall score for a single resource within one of the three components described above (for example, beaches within coastal habitats) requires: 1) a determination of resource size for habitats or relative abundance for biota, and 2) an evaluation of the sensitivity of the resource to spilled oil. Information on the resource size (habitats) or relative abundance (biota) used in the present analysis is presented in the tables and calcuations in Appendix I-1.

In the present analysis, the three ecological components are given equal theoretical importance. Each component is given a theoretical maximum score of 225 points. To attain or approach the theoretical maximum score, an ecological component must have a "high" concentration of highly-sensitive resources. In reality, no ecological component had sufficient concentrations to attain the theoretical maximum score.

The theoretical maximum score is determined by the calculation of the sensitivity of biota. Information on the distribution of biota in the planning areas is normally expressed as population estimates or as standing stocks. These measures are significantly different from those for the coastal and marine habitats (see below). The biota are measured as discrete units and not as components of a larger measurable whole, such as the resources included in the coastal and marine habitats. This difference

was accommodated by using professional judgment in interpreting available information on the abundance of the various categories of biota in the planning areas. The relative abundances were then rated as high, moderate, low, and none or negligible. The following numerical values were assigned to these ratings: high=5, moderate=3, low=1, and none or negligible=0. This information is included in the "Distribtuion of Resource" columns of the calculations (Table I-3 and Appendix I-1). Based upon the numerical values assigned to the sensitivity coefficients and to the relative abundances of biota, the maximum possible score for all biota in a planning area is 225 points.

The use of the theoretical maximum score assumes that each of the groups of biota evaluated in this analysis contributes to the sensitivity of the planning area. In none of the planning areas are all groups of biota present in high relative abundance. In fact, marine turtles do not occur in many planning areas. Their absence from a planning area or the absence of any other resource simply means that the resource does not contribute to the total score of the planning area. In the case of the marine turtles, their absence from most planning areas does not affect significantly the overall scores of the planning areas.

The principal difference between the calculations for habitats and biota is the mathematical limit imposed by the use of percentages in the habitat calculations. In order to preserve the equal theoretical importance of the three ecological components, the numerical values for the sesitivity coefficients are increased to high=225, moderate=135, and low=45. These values are assigned only to preserve the equal theoretical importance. The assignment of these values is not a statement that the sensitivities of coastal and marine habitats are 45 times greater than the sensitivities of marine biota. As a result of this change in the values attributed to the sensitivity coefficients for habitats, the theoretical maximum score for these components is also 225 points.

To obtain scores for coastal habitats, the various habitats were indentified for each planning area. Information on the size of coastal habitats is normally expressed in areal or linear units. For the calculations in Appendix I-1, sizes were expressed as percentages of the total length of the coast of the particular planning area. The sensitivities of the the various coastal habitats to spilled crude oil were determined. The percentage of the coast represented by the particular habitat was multiplied by the appropriate numerical value for the assigned sensitivity coefficient to produce a score for that habitat in the planning area. The sum of all of the scores of all coastal habitats in the planning area represents the evaluation of the sensitivity of the coast of the planning area to spilled oil. These calculations are illustrated in Table I-3.

The calculation for marine habitats in a planning area was similar to that for coastal habitats. In this instance, the percentage used in the calculation was the percentage of the planning area occupied by the particular habitat. An example of the calculation of the sensitivity of marine habitats is included in Table I-3. A major difference between the calculations for coastal and marine habitats is the lack of information on the extent of some marine habitats. In many of the calculations for marine habitats, only the areal extents of moderately and highly sensitive habitats were

defined. However, since the remaining area has a low sensitivity to spilled oil (Appendix I-2), lack of data on the areal extent of these habitats does not affect the calculation of the score. The total score for the sensitivity of marine habitats includes the combined contribution of all low sensitivity habitats as well as the moderately and highly sensitive habitats.

Finally, the scores for each of the three ecological components in a planning area were added to produce an overall total score.

B. Results

The scores for each of the three ecological components (coastal habitats, marine habitats, and biota) of the OCS planning areas are displayed in Table I-4. The calculations of the indices are included in Appendix I-1.

For coastal habitats, the principal variables which affect the scores are the sensitivity ratings for estuaries and wetlands and rocky beaches.

As a result of the low sensitivity of most marine habitats in the OCS planning areas, the scores for these habitats are lower than those for coastal habitats and biota, and they do not discriminate markedly among the OCS planning areas. The highly sensitive coral reefs do not occupy sufficient area to affect the overall scores for the South Atlantic and the Gulf of Mexico. The principal ecological component affecting the ratings for marine habitats is submerged vegetation.

The principal variables which affect the calculations for biota are their relative abundances in the various OCS planning areas. Information on relative abundance was collected from various OCS lease sale EIS's, draft chapters of the University of Maryland, Eastern Shore (UMES) study, other studies sponsored by the OCS Environmental Studies Program, and other published oceanographic data. The presence of relatively high populations of juvenile fish and shellfish, coastal and marine birds, marine mammals, and whales, all of which are judged to have a high sensitivity to spilled oil, is the major factor supporting the high scores of many Alaskan planning areas. Many of these populations are transients and migrate through several of the Alaskan planning areas. These migratory populations are included in the abundance rating for each planning area where they occur.

The overall total scores for each planning area are shown in Table I-5. Alaskan OCS planning areas occupy the extremes of this table. The Navarin Basin has the lowest score because it lacks coastal habitats. The planning areas with the highest scores are Hope Basin, North Aleutian Basin, St. George Basin, and Norton Basin. Because much of the information used in the calculation of relative marine productivity and environmental sensitivity is qualitative, each assinged value in the calculation has some degree of uncertainty. Thus, the scores provided in Table I-5 should be viewed as estimates surrounded by some undefined variance. Scores with small differences between them should be viewed as relatively equal.

TABLE I-5

Relative Marine Productivity and Environmental Sensitivity of the OCS Planning Areas

Planning Area	Overall Total Score
Hope Basin	349
North Aleutian Basin	327
St. George Basin	281
Norton Basin	280
Cook Inlet	272
Shumagin	265
Kodiak	264
Beaufort Sea	261
Washington-Oregon	256
Central Gulf of Mexico	254
Northern California	239
Gulf of Alaska	235
South Atlantic	230
Straits of Florida	228
Central California	227
Southern California	213
North Atlantic	209
Eastern Gulf of Mexico	208
Chukchi Sea	204
Mid-Atlantic	198
Western Gulf of Mexico	180
Navarin Basin	131

TABLE I-4

Relative Marine Productivity and Environmental Sensitivity of the OCS Planning Areas by Ecological Component

Coastal Habitats		Marine Habitats		Biota	
Planning Area	Score	Planning Area	Score	Planning Area	Score
Hope Basin	181	Norton Basin	63	North Aleutian Basin	128
North Aleutian Basin	153	St. George Basin	59	St. George Basin	118
Beaufort Sea	141	Hope Basin	56	Kodiak	116
Central Gulf of Mexico	130	Eastern Gulf of Mexico	52	Norton Basin	112
Washington-Oregon	127	Shumagin	50	Hope Basin	112
Cook Inlet	124	Beaufort Sea	50	Shumagin	110
Northern California	109	Chukchi Sea	49	Cook Inlet	102
Shumagin	105	Gulf of Alaska	49	Chukchi Sea	100
Norton Basin	105	Kodiak	47	South Atlantic	99
St. George Basin	104	North Aleutian Basin	46	Southern California	91
Kodiak	101	Cook Inlet	46	Gulf of Alaska	90
Straits of Florida	100	South Atlantic	46	Navarin Basin	86
Eastern Gulf of Mexico	99	Straits of Florida	45	Central California	85
Central California	97	Central Gulf of Mexico	45	Northern California	85
Gulf of Alaska	96	Western Gulf of Mexico	45	Washington-Oregon	84
South Atlantic	85	Southern California	45	Straits of Florida	83
North Atlantic	83	Central California	45	Mid-Atlantic	83
Southern California	77	Northern California	45	Western Gulf of Mexico	81
Mid-Atlantic	70	Washington-Oregon	45	North Atlantic	81
Chukchi Sea	55	Mid-Atlantic	45	Central Gulf of Mexico	79
Western Gulf of Mexico	54	North Atlantic	45	Beaufort Sea	70
Navarin Basin	0	Navarin Basin	45	Eastern Gulf of Mexico	57

The results of this analysis are consistent with available information on the relative sensitivity of the resources to spilled oil. The results are also consistent with the current concepts of relative sensitivity of coastal and marine habitats (COPRDM, 1981; NRC, 1985). This is most clearly shown for the Navarin Basin where coastal habitats are negligible. In addition, the presence of high populations of sensitive biota (coastal and marine birds, marine mammals, whales, juvenile fish and shellfish) are the major factors supporting the high overall scores of the Alaskan planning areas. The ecological component which has the least effect on the overall scores is marine habitats. This results from the assumption that spilled oil cannot be transported in significant amounts from the surface of the ocean to most benthic communities. The most sensitive marine habitats that could be affected are submerged vegetation and coral reefs. These habitats do not occupy a significant portion of any planning area.

Several commenters criticized the analysis of relative marine productivity and environmental sensitivity because of dissatisfaction with the results. In particular, the scores for marine habitats were criticized because the sensitivity of marine habitats in many diverse planning areas were scored the same due to lack of data. However, this lack of data on areal extent of marine habitats is not considered critical as most marine habitats are judged to have low sensitivity to spilled oil and have been provided low sensitivity ratings.

The method used to generate Overall Total Scores was modified to ascertain the significance of having equal scores for marine habitats in diverse planning areas. The ranking of planning areas as to their relative marine productivity and environmental sensitivity was determined both as a composite of the individual scores for coastal habitats, marine habitats, and biota (Table I-5) and for coastal habitats and biota without marine habitats (Table I-6). The final order of planning areas is not changed significantly whether marine habitats are considered or not. As stated previously, scores with small differences between them should be viewed as relatively equal. Thus, the model is not sensitive to the lack of data on areal extent of low-sensitivity marine habitats.

The results of this analysis should not be construed as indicating the level of impacts expected as a result of OCS development. In this analysis, sensitivity is determined from the likely response of the resource to the environmental perturbation without consideration of risk, likelihood of adverse impact, or vulnerability. Thus, the sensitivity ratings represent a conservative analysis. Additional factors would need to be considered to determine the expected level of impacts in a planning area from OCS oil and gas operations. These factors include the projected amount of hydrocarbon resources, their probable location within the planning area, the number and trajectory of hypothetical oil spills, and the location of possible spill sites, among others.

A high overall score or the presence of many sensitive resources in a planning area does not necessarily imply a high level of adverse effects from OCS development. Even those areas ranked with relatively low scores possess sensitive resources which will require consideration of specific environmental impacts at the sale stage and evaluation to determine the need for special protective measures.

TABLE I-6

Relative Marine Productivity and Environmental Sensitivity of the OCS Planning Areas Calculated as the Sum of the Scores for Coastal Habitats and Biota

Planning Area	Score
Hope Basin	293
North Aleutian Basin	281
Cook Inlet	226
St. George Basin	222
Norton Basin	217
Kodiak	217
Shumagin	215
Beaufort Sea	211
Washington-Oregon	211
Central Gulf of Mexico	209
Northern California	194
Gulf of Alaska	186
South Atlantic	184
Straits of Florida	183
Central California	182
Southern California	168
North Atlantic	164
Eastern Gulf of Mexico	156
Chukchi Sea	155
Mid-Atlantic	153
Western Gulf of Mexico	135
Navarin Basin	86

The present analysis of relative marine productivity and environmental sensitivity is one step in a continuing process of environmental assessment. The concepts presented in the present analysis will be evaluated and discussed in greater detail in the EIS for the proposed leasing program. Further analysis of environmental information will occur in subsequent lease-sale specific EIS's.

In relation to the 1982 analysis, the present analysis provides the basis for incorporating new information on the distribution of resources and their sensitivities to spilled oil into a systematic calculation. The present analysis still contains some of the assumptions and judgments contained in the 1982 analysis. Many of these may be replaced by quantitative information by the time the next relative marine productivity and environmental sensitivity analysis must be performed. The OCS Environmental Studies Program is sponsoring several studies which will provide relevant information for the next analysis.

C. Background Evaluations

An extensive body of literature was reviewed as background to the environmental sensitivity values assigned to the planning area calculations included in Appendix I-1. This material was summarized in Appendix I-2 of the Draft Proposed Program. Appendix I-2 included an extensive bibliography of the materials consulted prior to assigning relative values to the planning areas. This material summarized available information on the environmental sensitivity of specific habitats by categories identified as estuaries and wetlands, beaches, submerged aquatic vegetation, submarine canyons, shelf break zone, coral reefs, and live hard bottoms. The sensitivity of different types of marine biota was assessed by categories identified as plankton, mud/sand benthos, fish and shellfish, marine birds, coastal birds, marine turtles, and marine mammals. Each of these habitats and biotic components was evaluated for its sensitivity to accidental contact with crude oil. Such sensitivity varies widely in response to factors such as period of exposure, density and chemical composition of the oil, amount of weathering prior to contact, and other factors.

The environmental sensitivity of various habitats and organisms was also considered with respect to other impact-producing factors. These factors were not used in the calculation of environmental sensitivity for the reasons given on page I-8 of this analysis.

1. Drilling discharges (muds, cuttings, and produced waters).
2. Noise generated by OCS activities.
3. Habitat alteration from the installation of OCS facilities.
4. Air emissions from OCS operations.

The potential effects of these factors are singularly more limited in extent than the potential effects of a large oil spill. However, the cumulative effects of these factors may be more extensive and long-lasting than the effects of a large spill. Several means are available to mitigate or lessen the adverse effects of these factors. As a result, spilled oil was the factor of greatest concern in the present analysis.

All of the material presented in Appendix I-2 of the Draft Proposed Program has been reevaluated in response to public comment and a revised version has been prepared. This document has not been reproduced for general review in the Proposed Program. It is, however, a part of the record for the Proposed Program. Copies of the revised appendix may be requested from the U.S. Department of the Interior, Minerals Management Service, Offshore Leasing Management Division, Mail Stop 645, Washington, D.C. 20240.

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* Study sponsored by the OCS Environmental Studies Program

Appendix I-1

RELATIVE MARINE PRODUCTIVITY AND ENVIRONMENTAL SENSITIVITY ANALYSIS: OIL SPILLS

PLANNING AREA CALCULATIONS

RELATIVE MARINE PRODUCTIVITY/ENVIRONMENTAL SENSITIVITY ANALYSIS: OIL SPILLS

PLANNING AREA CALCULATIONS

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Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: North Atlantic

Overall Total Score: 209

	Distribution of Resource (1)	(2)	Sensitivity Coefficient (3)	(4)	Score (5)
Coastal Habitats	Miles				
Estuaries/Wetlands	217	5.8	High	225	13.1
Sandy Beaches	2378	63.6	Low	45	28.6
Rocky Beaches	1145	30.6	Moderate	135	41.3
TOTAL	3740				83.0
Marine Habitats	Acres				
Submerged Vegetation			High	225	
Submarine Canyons			Low	45	
Coral Reefs			High	225	
Hard Bottoms			Low	45	
Shelf Break Zone	6,495,900	13.2	Low	45	
Mud/Sand Bottom			Low	45	
TOTAL	49,000,000				45
Biota					
Phytoplankton	High	5	Low	1	5
Juvenile Fish/Shellfish	High	5	High	5	25
Adult Fish/Shellfish	High	5	Moderate	3	15
Mud/Sand Benthos	Moderate	3	Low	1	3
Coastal Birds	Moderate	3	High	5	15
Marine Birds	Low	1	High	5	5
Marine Turtles	Low	1	Moderate	3	3
Marine Mammals	Low	1	High	5	5
Whales	Low	1	High	5	5
TOTAL					81

(1) Linear or areal extent of habitat; abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.

Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: Mid-Atlantic

Overall Total Score: 198

	Distribution of Resource (1)	(2)	Sensitivity Coefficient (3)	(4)	Score (5)
Coastal Habitats	Miles				
Estuaries/Wetlands	80	12.7	High	225	28.6
Sandy Beaches	534	84.9	Low	45	38.2
Rocky Beaches	15	2.4	Moderate	135	3.2
TOTAL	629				70.0
Marine Habitats	Acres				
Submerged Vegetation	Negligible	0.0	High	225	0.00
Submarine Canyons	598,900	0.73	Low	45	0.33
Coral Reefs	Negligible	0.0	High	225	0.00
Hard Bottoms	Negligible	0.0	Low	45	0.00
Shelf Break Zone	580,700	0.7	Low	45	0.43
Mud/Sand Bottom	80,617,745	98.6	Low	45	44.37
TOTAL	82,000,000				45.13
Biota					
Phytoplankton	High	5	Low	1	5
Juvenile Fish/Shellfish	High	5	High	5	25
Adult Fish/Shellfish	Moderate	3	Moderate	3	9
Mud/Sand Benthos	Low	1	Low	1	1
Coastal Birds	Moderate	3	High	5	15
Marine Birds	Moderate	3	High	5	15
Marine Turtles	Moderate	3	Low	1	3
Marine Mammals	Low	1	High	5	5
Whales	Low	1	High	5	5
TOTAL					83

(1) Linear or areal extent of habitat; abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.

Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: South Atlantic

Overall Total Score: 230

	Distribution of Resource (1)	(2)	Sensitivity Coefficient (3)	(4)	Score (5)
Coastal Habitats	Miles				
Estuaries/Wetlands	378	44.1	Moderate	135	59.5
Sandy Beaches	479	55.9	Low	45	25.2
Rocky Beaches	Negligible	0.0	Low	45	0.0
TOTAL	857				84.7
Marine Habitats	Acres				
Submerged Vegetation	21,120	0.02	High	225	0.05
Submarine Canyons	74,880	0.08	Low	45	0.04
Coral Reefs	481,100	0.49	High	225	1.10
Hard Bottoms	1,852,250	1.87	Low	45	0.84
Shelf Break Zone	3,826,000	3.85	Low	45	1.73
Mud/Sand Bottom	92,744,650	93.7	Low	45	42.16
TOTAL	99,000,000				45.92
Biota					
Phytoplankton	Moderate	3	Low	1	3
Juvenile Fish/Shellfish	Moderate	3	High	5	15
Adult Fish/Shellfish	High	5	Moderate	3	15
Mud/Sand Benthos	Low	1	Low	1	1
Coastal Birds	High	5	High	5	25
Marine Birds	Moderate	3	High	5	15
Marine Turtles	High	5	Moderate	3	15
Marine Mammals	Low	1	High	5	5
Whales	Low	1	High	5	5
TOTAL					99

(1) Linear or areal extent of habitat; abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.

Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: Straits of Florida

Overall Total Score: 228

	Distribution of Resource (1)	(2)	Sensitivity Coefficient (3)	(4)	Score (5)
Coastal Habitats	Miles				
Estuaries/Wetlands	270	60.7	Moderate	135	81.9
Sandy Beaches	175	39.3	Low	45	17.7
Rocky Beaches	Negligible	0.0	Low	45	0.0
TOTAL	445				99.6
Marine Habitats	Acres				
Submerged Vegetation			High	225	
Submarine Canyons			Low	45	
Coral Reefs			High	225	
Hard Bottoms			Low	45	
Shelf Break Zone			Low	45	
Mud/Sand Bottom			Low	45	
TOTAL	8,000,000				45
Biota					
Phytoplankton	Moderate	3	Low	1	3
Juvenile Fish/Shellfish	Moderate	3	High	5	15
Adult Fish/Shellfish	Moderate	3	Moderate	3	9
Mud/Sand Benthos	Low	1	Low	1	1
Coastal Birds	Moderate	3	High	5	15
Marine Birds	Moderate	3	High	5	15
Marine Turtles	High	5	Moderate	3	15
Marine Mammals	Low	1	High	5	5
Whales	Low	1	High	5	5
TOTAL					83

(1) Linear or areal extent of habitat; abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.

Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: Eastern Gulf of Mexico Overall Total Score: 208

	Distribution of Resource (1)	(2)	Sensitivity Coefficient (3)	(4)	Score (5)
Coastal Habitats	Miles				
Estuaries/Wetlands	1234	59.7	Moderate	135	80.6
Sandy Beaches	833	40.3	Low	45	18.4
Rocky Beaches	Negligible	0.0	Low	45	0.0
TOTAL	2067				99.0
Marine Habitats	Acres				
Submerged Vegetation	2,026,333	3.5	High	225	7.9
Submarine Canyons	Negligible	0.0	Low	45	
Coral Reefs	232,500	0.4	High	225	0.9
Hard Bottoms	10,874,000	18.7	Low	45	
Shelf Break Zone			Low	45	
Mud/Sand Bottom			Low	45	
TOTAL	58,000,000				52.0
Biota					
Phytoplankton	Low	1	Low	1	1
Juvenile Fish/Shellfish	Low	1	High	5	5
Adult Fish/Shellfish	Low	1	Moderate	3	3
Mud/Sand Benthos	Moderate	3	Low	1	3
Coastal Birds	Moderate	3	High	5	15
Marine Birds	Low	1	High	5	5
Marine Turtles	High	5	Moderate	3	15
Marine Mammals	Low	1	High	5	5
Whales	Low	1	High	5	5
TOTAL					57

(1) Linear or areal extent of habitat; abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.

Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: Central Gulf of Mexico Overall Total Score: 254

	Distribution of Resource (1)	(2)	Sensitivity Coefficient (3)	(4)	Score (5)
Coastal Habitats	Miles				
Estuaries/Wetlands	2105	94.7	Moderate	135	127.9
Sandy Beaches	118	5.4	Low	45	2.4
Rocky Beaches	Negligible	0.0	Low	45	0.00
TOTAL	2223				130.3
Marine Habitats	Acres				
Submerged Vegetation	71,139	0.16	High	225	0.36
Submarine Canyons	0	0.00	Low	45	0.00
Coral Reefs	0	0.00	High	225	0.00
Hard Bottoms	21,263	0.05	Low	45	0.03
Shelf Break Zone	1,716,480	3.81	Low	45	1.72
Mud/Sand Bottom	44,191,118	96.0	Low	45	43.20
TOTAL	46,000,000				45.30
Biota					
Phytoplankton	Low	1	Low	1	1
Juvenile Fish/Shellfish	High	5	High	5	25
Adult Fish/Shellfish	High	5	Moderate	3	15
Mud/Sand Benthos	Moderate	3	Low	1	3
Coastal Birds	Moderate	3	High	5	15
Marine Birds	Low	1	High	5	5
Marine Turtles	High	5	Low	1	5
Marine Mammals	Low	1	High	5	5
Whales	Low	1	High	5	5
TOTAL					79

(1) Linear or areal extent of habitat; abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.

Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: Western Gulf of Mexico

Overall Total Score: 180

	Distribution of Resource (1)	(2)	Sensitivity Coefficient (3)	(4)	Score (5)
Coastal Habitats	Miles				
Estuaries/Wetlands	56	10.2	Moderate	135	13.8
Sandy Beaches	489	89.8	Low	45	40.4
Rocky Beaches	Negligible	0.0	Low	45	0.0
TOTAL	545				54.2
Marine Habitats	Acres				
Submerged Vegetation	Negligible	0.00	High	225	0.0
Submarine Canyons	Negligible	0.00	Low	45	0.0
Coral Reefs	5,560	0.02	High	225	0.05
Hard Bottoms	51,650	0.15	Low	45	0.07
Shelf Break Zone	1,607,040	4.55	Low	45	2.05
Mud/Sand Bottom	33,642,765	95.3	Low	45	42.89
TOTAL	35,300,000				45.06
Biota					
Phytoplankton	Low	1	Low	1	1
Juvenile Fish/Shellfish	Moderate	3	High	5	15
Adult Fish/Shellfish	Moderate	3	Moderate	3	9
Mud/Sand Benthos	Low	1	Low	1	1
Coastal Birds	High	5	High	5	25
Marine Birds	Low	1	High	5	5
Marine Turtles	High	5	Moderate	3	15
Marine Mammals	Low	1	High	5	5
Whales	Low	1	High	5	5
TOTAL					81

(1) Linear or areal extent of habitat; abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.

Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: Southern California

Overall Total Score: 213

	Distribution of Resource (1)	(2)	Sensitivity Coefficient (3)	(4)	Score (5)
Coastal Habitats	Miles				
Estuaries/Wetlands	2	0.2	Moderate	135	0.3
Sandy Beaches	459	64.6	Low	45	29.1
Rocky Beaches	250	35.2	Moderate	135	47.5
TOTAL	711				76.9
Marine Habitats	Acres				
Submerged Vegetation			High	225	
Submarine Canyons			Low	45	
Coral Reefs			High	225	
Hard Bottoms			Low	45	
Shelf Break Zone			Low	45	
Mud/Sand Bottom			Low	45	
TOTAL	30,000,000				45
Biota					
Phytoplankton	High	5	Low	1	5
Juvenile Fish/Shellfish	Moderate	3	High	5	15
Adult Fish/Shellfish	Moderate	3	Moderate	3	9
Mud/Sand Benthos	Low	1	Low	1	1
Coastal Birds	Moderate	3	High	5	15
Marine Birds	Moderate	3	High	5	15
Marine Turtles	Low	1	Low	1	1
Marine Mammals	Moderate	3	High	5	15
Whales	Moderate	3	High	5	15
TOTAL					91

(1) Linear or areal extent of habitat; abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.

Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: Central California — Overall Total Score: 227

	Distribution of Resource (1)	(2)	Sensitivity Coefficient (3)	(4)	Score (5)
Coastal Habitats	Miles				
Estuaries/Wetlands	2	0.4	High	225	0.9
Sandy Beaches	162	42.3	Low	45	19.0
Rocky Beaches	220	57.3	Moderate	135	77.4
TOTAL	384				97.3
Marine Habitats	Acres				
Submerged Vegetation			High	225	
Submarine Canyons	247,680	1.7	Low	45	
Coral Reefs			High	225	
Hard Bottoms			Low	45	
Shelf Break Zone			Low	45	
Mud/Sand Bottom			Low	45	
TOTAL	15,000,000				45
Biota					
Phytoplankton	High	5	Low	1	5
Juvenile Fish/Shellfish	Moderate	3	High	5	15
Adult Fish/Shellfish	Low	1	Moderate	3	3
Mud/Sand Benthos	Low	1	Low	1	1
Coastal Birds	Moderate	3	High	5	15
Marine Birds	Moderate	3	High	5	15
Marine Turtles	Low	1	Low	1	1
Marine Mammals	Moderate	3	High	5	15
Whales	Moderate	3	High	5	15
TOTAL					85

(1) Linear or areal extent of habitat; abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.

Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: Northern California — Overall Total Score: 239

	Distribution of Resource (1)	(2)	Sensitivity Coefficient (3)	(4)	Score (5)
Coastal Habitats	Miles				
Estuaries/Wetlands	9	3.0	High	225	6.8
Sandy Beaches	96	31.7	Low	45	14.3
Rocky Beaches	198	65.4	Moderate	135	88.3
TOTAL	303				109.3
Marine Habitats	Acres				
Submerged Vegetation			High	225	
Submarine Canyons	305,280	1.1	Low	45	
Coral Reefs			High	225	
Hard Bottoms			Low	45	
Shelf Break Zone			Low	45	
Mud/Sand Bottom			Low	45	
TOTAL	29,000,000				45
Biota					
Phytoplankton	High	5	Low	1	5
Juvenile Fish/Shellfish	Moderate	3	High	5	15
Adult Fish/Shellfish	Low	1	Moderate	3	3
Mud/Sand Benthos	Low	1	Low	1	1
Coastal Birds	Moderate	3	High	5	15
Marine Birds	Moderate	3	High	5	15
Marine Turtles	Low	1	Low	1	1
Marine Mammals	Moderate	3	High	5	15
Whales	Moderate	3	High	5	15
TOTAL					85

(1) Linear or areal extent of habitat; abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.

Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: Washington-Oregon

Overall Total Score: 256

	Distribution of Resource (1)	(2)	Sensitivity Coefficient (3)	(4)	Score (5)
Coastal Habitats	Miles				
Estuaries/Wetlands	69	10.0	High	225	22.5
Sandy Beaches	130	19.0	Low	45	8.6
Rocky Beaches	486	71.0	Moderate	135	95.9
TOTAL	685				127.0
Marine Habitats	Acres				
Submerged Vegetation			Moderate	135	
Submarine Canyons			Low	45	
Coral Reefs			High	225	
Hard Bottoms			Low	45	
Shelf Break Zone			Low	45	
Mud/Sand Bottom			Low	45	
TOTAL	47,000,000				45
Biota					
Phytoplankton	High	5	Low	1	5
Juvenile Fish/Shellfish	Moderate	3	High	5	15
Adult Fish/Shellfish	Low	1	Moderate	3	3
Mud/Sand Benthos	Low	1	Low	1	1
Coastal Birds	Moderate	3	High	5	15
Marine Birds	Moderate	3	High	5	15
Marine Turtles	Negligible	0	Low	1	0
Marine Mammals	Moderate	3	High	5	15
Whales	Moderate	3	High	5	15
TOTAL					84

(1) Linear or areal extent of habitat; abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.

Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: Gulf of Alaska

Overall Total Score: 235

	Distribution of Resource (1)	(2)	Sensitivity Coefficient (3)	(4)	Score (5)
Coastal Habitats	Miles				
Estuaries/Wetlands		11.2	High	225	25.2
Sandy Beaches		54.4	Low	45	24.5
Rocky Beaches		34.5	Moderate	135	46.6
TOTAL					96.3
Marine Habitats	Acres				
Submerged Vegetation	5,192,320	3.9	Moderate	135	5.3
Submarine Canyons			Low	45	
Coral Reefs		0.0	High	225	
Hard Bottoms			Low	45	
Shelf Break Zone			Low	45	
Mud/Sand Bottom			Low	45	
TOTAL	133,000,000				48.5
Biota					
Phytoplankton	High	5	Low	1	5
Juvenile Fish/Shellfish	Moderate	3	High	5	15
Adult Fish/Shellfish	Moderate	3	Moderate	3	9
Mud/Sand Benthos	Low	1	Low	1	1
Coastal Birds	Low	1	High	5	5
Marine Birds	Moderate	3	High	5	15
Marine Turtles	None	0	Low	1	0
Marine Mammals	High	5	High	5	25
Whales	Moderate	3	High	5	15
TOTAL					90

(1) Linear or areal extent of habitat; abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.

Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: Kodiak

Overall Total Score: 264

	Distribution of Resource (1)	(2)	Sensitivity Coefficient (3)	(4)	Score (5)
Coastal Habitats	Miles				
Estuaries/Wetlands		1.6	High	225	3.6
Sandy Beaches		39.5	Low	45	17.8
Rocky Beaches		58.9	Moderate	135	79.5
TOTAL					100.9
Marine Habitats	Acres				
Submerged Vegetation	1,812,480	2.0	Moderate	135	2.7
Submarine Canyons			Low	45	
Coral Reefs		0.0	High	225	
Hard Bottoms			Low	45	
Shelf Break Zone			Low	45	
Mud/Sand Bottom			Low	45	
TOTAL	89,000,000				46.8
Biota					
Phytoplankton	High	5	Low	1	5
Juvenile Fish/Shellfish	Moderate	3	High	5	15
Adult Fish/Shellfish	High	5	Moderate	3	15
Mud/Sand Benthos	Low	1	Low	1	1
Coastal Birds	High	5	High	5	25
Marine Birds	High	5	High	5	25
Marine Turtles	None	0	Low	1	0
Marine Mammals	Moderate	3	High	5	15
Whales	Moderate	3	High	5	15
TOTAL					116

(1) Linear or areal extent of habitat; abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.

Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: Cook Inlet

Overall Total Score: 272

	Distribution of Resource (1)	(2)	Sensitivity Coefficient (3)	(4)	Score (5)
Coastal Habitats	Miles				
Estuaries/Wetlands	215	14.1	High	225	31.7
Sandy Beaches	396	26.0	Low	45	11.7
Rocky Beaches	913	59.9	Moderate	135	80.9
TOTAL	1524				124.3
Marine Habitats	Acres				
Submerged Vegetation	80,640	1.0	Moderate	135	1.4
Submarine Canyons			Low	45	
Coral Reefs		0.0	High	225	
Hard Bottoms			Low	45	
Shelf Break Zone			Low	45	
Mud/Sand Bottom			Low	45	
TOTAL	5,000,000				45.9
Biota					
Phytoplankton	High	5	Low	1	5
Juvenile Fish/Shellfish	Moderate	3	High	5	15
Adult Fish/Shellfish	Moderate	3	Moderate	3	9
Mud/Sand Benthos	Low	1	Moderate	3	3
Coastal Birds	High	5	High	5	25
Marine Birds	Moderate	3	High	5	15
Marine Turtles	None	0	Low	1	0
Marine Mammals	Moderate	3	High	5	15
Whales	Moderate	3	High	5	15
TOTAL					102

(1) Linear or areal extent of habitat; abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.

Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: Shumagin

Overall Total Score: 265

	Distribution of Resource (1)	(2)	Sensitivity Coefficient (3)	(4)	Score (5)
Coastal Habitats	Miles				
Estuaries/Wetlands		1.0	High	225	2.3
Sandy Beaches		34.0	Low	45	15.3
Rocky Beaches		65.0	Moderate	135	87.8
TOTAL					105.4
Marine Habitats	Acres				
Submerged Vegetation	4,502,400	5.36	Moderate	135	7.2
Submarine Canyons			Low	45	
Coral Reefs		0.0	High	225	
Hard Bottoms			Low	45	
Shelf Break Zone			Low	45	
Mud/Sand Bottom			Low	45	
TOTAL	83,000,000				49.8
Biota					
Phytoplankton	High	5	Low	1	5
Juvenile Fish/Shellfish	Moderate	3	High	5	15
Adult Fish/Shellfish	Moderate	3	Moderate	3	9
Mud/Sand Benthos	Low	1	Low	1	1
Coastal Birds	High	5	High	5	25
Marine Birds	High	5	High	5	25
Marine Turtles	None	0	Low	1	0
Marine Mammals	Moderate	3	High	5	15
Whales	Moderate	3	High	5	15
TOTAL					110

(1) Linear or areal extent of habitat; abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.

Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: North Aleutian Basin

Overall Total Score: 327

	Distribution of Resource (1)	(2)	Sensitivity Coefficient (3)	(4)	Score (5)
Coastal Habitats	Miles				
Estuaries/Wetlands		32.6	High	225	73.4
Sandy Beaches		13.1	Low	45	5.9
Rocky Beaches		54.3	Moderate	135	73.3
TOTAL					152.6
Marine Habitats	Acres				
Submerged Vegetation	288,000	.9	Moderate	135	1.2
Submarine Canyons			Low	45	
Coral Reefs		0.0	High	225	
Hard Bottoms			Low	45	
Shelf Break Zone			Low	45	
Mud/Sand Bottom			Low	45	
TOTAL	32,000,000				45.8
Biota					
Phytoplankton	High	5	Low	1	5
Juvenile Fish/Shellfish	High	5	High	5	25
Adult Fish/Shellfish	High	5	Moderate	3	15
Mud/Sand Benthos	Moderate	3	Low	1	3
Coastal Birds	High	5	High	5	25
Marine Birds	High	5	High	5	25
Marine Turtles	None	0	Low	1	0
Marine Mammals	Moderate	3	High	5	15
Whales	Moderate	3	High	5	15
TOTAL					128

(1) Linear or areal extent of habitat; abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.

Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: St. George Basin — Overall Total Score: 281

	Distribution of Resource (1)	(2)	Sensitivity Coefficient (3)	(4)	Score (5)
Coastal Habitats	Miles				
Estuaries/Wetlands		0.3	High	225	0.7
Sandy Beaches		26.3	Low	45	11.9
Rocky Beaches		67.5	Moderate	135	91.1
TOTAL					103.7
Marine Habitats	Acres				
Submerged Vegetation	10,946,560	15.6	Moderate	135	21.1
Submarine Canyons			Low	45	
Coral Reefs		0.0	High	225	
Hard Bottoms			Low	45	
Shelf Break Zone			Low	45	
Mud/Sand Bottom			Low	45	
TOTAL	70,000,000				59.0
Biota					
Phytoplankton	High	5	Low	1	5
Juvenile Fish/Shellfish	High	5	High	5	25
Adult Fish/Shellfish	High	5	Moderate	3	15
Mud/Sand Benthos	Moderate	3	Low	1	3
Coastal Birds	Moderate	3	High	5	15
Marine Birds	High	5	High	5	25
Marine Turtles	None	0	Low	1	0
Marine Mammals	Moderate	3	High	5	15
Whales	Moderate	3	High	5	15
TOTAL					118

(1) Linear or areal extent of habitat; abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.

Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: Navarin Basin — Overall Total Score: 131

	Distribution of Resource (1)	(2)	Sensitivity Coefficient (3)	(4)	Score (5)
Coastal Habitats	Miles				
Estuaries/Wetlands	0		High	225	
Sandy Beaches	0		Low	45	
Rocky Beaches	0		Moderate	135	
TOTAL					0
Marine Habitats	Acres				
Submerged Vegetation			Moderate	135	
Submarine Canyons			Low	45	
Coral Reefs			High	225	
Hard Bottoms			Low	45	
Shelf Break Zone			Low	45	
Mud/Sand Bottom			Low	45	
TOTAL	37,000,000				45
Biota					
Phytoplankton	Moderate	3	Low	1	3
Juvenile Fish/Shellfish	Moderate	3	High	5	15
Adult Fish/Shellfish	High	5	Moderate	3	15
Mud/Sand Benthos	Moderate	3	Low	1	3
Coastal Birds	Low	1	High	5	5
Marine Birds	High	5	High	5	25
Marine Turtles	None	0	Low	1	0
Marine Mammals	Moderate	3	High	5	15
Whales	Low	1	High	5	5
TOTAL					86

(1) Linear or areal extent of habitat; abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.

Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: Norton Basin

Overall Total Score: 280

	Distribution of Resource (1)	(2)	Sensitivity Coefficient (3)	(4)	Score (5)
Coastal Habitats	Miles				
Estuaries/Wetlands	623	33.4	High	225	75.2
Sandy Beaches	382	20.5	Low	45	9.3
Rocky Beaches	859	46.1	Low	45	20.7
TOTAL	1864				105.2
Marine Habitats	Acres				
Submerged Vegetation	4,998,400	19.9	Moderate	135	26.9
Submarine Canyons			Low	45	
Coral Reefs		0.0	High	225	
Hard Bottoms			Low	45	
Shelf Break Zone			Low	45	
Mud/Sand Bottom			Low	45	
TOTAL	25,000,000				62.9
Biota					
Phytoplankton	Moderate	3	Low	1	3
Juvenile Fish/Shellfish	Low	1	High	5	5
Adult Fish/Shellfish	Low	1	Moderate	3	3
Mud/Sand Benthos	Low	1	Low	1	1
Coastal Birds	High	5	High	5	25
Marine Birds	High	5	High	5	25
Marine Turtles	None	0	Low	1	0
Marine Mammals	High	5	High	5	25
Whales	High	5	High	5	25
TOTAL					112

(1) Linear or areal extent of habitat; abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.

Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: Hope Basin

Overall Total Score: 349

	Distribution of Resource (1)	(2)	Sensitivity Coefficient (3)	(4)	Score (5)
Coastal Habitats	Miles				
Estuaries/Wetlands		75.7	High	225	170.3
Sandy Beaches		4.9	Low	45	2.2
Rocky Beaches		19.5	Low	45	8.8
TOTAL					181.3
Marine Habitats	Acres				
Submerged Vegetation	1,499,520	12.5	Moderate	135	16.9
Submarine Canyons			Low	45	
Coral Reefs		0.0	High	225	
Hard Bottoms			Low	45	
Shelf Break Zone			Low	45	
Mud/Sand Bottom			Low	45	
TOTAL	12,000,000				56.3
Biota					
Phytoplankton	Low	1	Low	1	1
Juvenile Fish/Shellfish	Low	1	High	5	5
Adult Fish/Shellfish	Low	1	Moderate	3	3
Mud/Sand Benthos	Moderate	3	Low	1	3
Coastal Birds	High	5	High	5	25
Marine Birds	High	5	High	5	25
Marine Turtles	None	0	Low	1	0
Marine Mammals	High	5	High	5	25
Whales	High	5	High	5	25
TOTAL					112

(1) Linear or areal extent of habitat; abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.

Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: Chukchi Sea — Overall Total Score: 204

	Distribution of Resource (1)	(2)	Sensitivity Coefficient (3)	(4)	Score (5)
Coastal Habitats	Miles				
Estuaries/Wetlands		5.5	High	225	12.4
Sandy Beaches		74.4	Low	45	33.5
Rocky Beaches		20.2	Low	45	9.1
TOTAL					55.0
Marine Habitats	Acres				
Submerged Vegetation	1,420,800	4.7	Moderate	135	6.4
Submarine Canyons			Low	45	
Coral Reefs		0.0	High	225	
Hard Bottoms			Low	45	
Shelf Break Zone			Low	45	
Mud/Sand Bottom			Low	45	
TOTAL	29,000,000				49.2
Biota					
Phytoplankton	Low	1	Low	1	1
Juvenile Fish/Shellfish	Low	1	High	5	5
Adult Fish/Shellfish	Low	1	Moderate	3	3
Mud/Sand Benthos	Low	1	Low	1	1
Coastal Birds	High	5	High	5	25
Marine Birds	Moderate	3	High	5	15
Marine Turtles	None	0	Low	1	0
Marine Mammals	High	5	High	5	25
Whales	High	5	High	5	25
TOTAL					100

(1) Linear or areal extent of habitat; abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.

Relative Marine Productivity/Environmental Sensitivity Analysis

Oil Spills

Planning Area: Beaufort Sea — Overall Total Score: 261

	Distribution of Resource (1)	(2)	Sensitivity Coefficient (3)	(4)	Score (5)
Coastal Habitats	Miles				
Estuaries/Wetlands		52.9	High	225	119.0
Sandy Beaches		46.9	Low	45	21.1
Rocky Beaches		3.0	Low	45	1.4
TOTAL					141.5
Marine Habitats	Acres				
Submerged Vegetation	2,497,920	5.1	Moderate	135	6.9
Submarine Canyons			Low	45	
Coral Reefs			High	225	
Hard Bottoms			Low	45	
Shelf Break Zone			Low	45	
Mud/Sand Bottom			Low	45	
TOTAL	52,000,000				49.6
Biota					
Phytoplankton	Low	1	Low	1	1
Juvenile Fish/Shellfish	Low	1	High	5	5
Adult Fish/Shellfish	Low	1	Moderate	3	3
Mud/Sand Benthos	Low	1	Low	1	1
Coastal Birds	High	5	High	5	25
Marine Birds	Low	1	High	5	5
Marine Turtles	None	0	Low	1	0
Marine Mammals	Moderate	3	High	5	15
Whales	Moderate	3	High	5	15
TOTAL					70

(1) Linear or areal extent of habitat; abundance of biota.
(2) Percentage of total coastal or marine habitat in the planning area; abundance of biota in planning area in relation to abundance in all other OCS planning areas. Rated as high=5, moderate=3, low=1, and none or negligible=0.
(3) Adjective describing sensitivity in terms of the severity of impact from spilled oil and recovery time as high, moderate or low.
(4) Numerical value associated with the adjective under (3) as high=225, moderate=135 or low=45 for coastal and marine habitats, and high=5, moderate=3 or low=1 for biota. Thus, the maximum possible total score for each ecological component is 225.
(5) Product of (2) and (4) divided by 100 for coastal and marine habitats. Product of (2) and (4) for marine biota.

Appendix I-2

BACKGROUND PAPERS ON ENVIRONMENTAL SENSITIVITY

BACKGROUND PAPERS ON ENVIRONMENTAL SENSITIVITY

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Sensitivity of Coastal Habitats to Oil Spills

Several methods have been developed to rank various shoreline types in terms of their sensitivity to oil contamination. Owens (1971) defined nine shoreline types in terms of their sensitivity to oil spills and suggested the basic relationship between shoreline type, oil persistence, and biological sensitivity. Hayes, Brown, and Michel (1976) used the longevity of oil in different environments in the absence of cleanup effects to define 10 shoreline types in terms of an oil susceptibility index. This approach was modified by Ruby (1977), Gundlach and Hayes (1978), Ruby and Hayes (1978), and Michel, Hayes, and Brown (1978) to include some biological considerations. This modified approach was designated the "Oil Spill Vulnerability Index." Nummedal (1980) used oil retention potential to define eight shoreline types in his study of the Beaufort Sea coast of Alaska. Gundlach, Getter, and Hayes (1980) expanded the vulnerability index of Gundlach and Hayes (1978) to include locations and seasonal use information for sensitive biological resources. This information was portrayed on maps, and the index was called the "Environmental Sensitivity Index." Woodward-Clyde Consultants (1982), in a study conducted for the Minerals Management Service, developed "oil residence and geological sensitivity indexes" for central and northern California coastal marine habitats. The biological sensitivity index included resources that are permanent within the study area, that spend most of their time there, or that are dependent upon the area for some part of their life history. The approach of using two separate indexes instead of a single index based primarily on shoreline type was found to yield more valuable information with respect to potential effects of spilled oil.

Estuaries and Wetlands

Estuaries are semienclosed coastal bodies of water having free connection with the open sea, and within which seawater is measurably diluted with fresh water (Pritchard, 1967). Estuaries and their associated wetlands are characterized by daily or seasonal shifts in salinity, temperature, and desiccation, such that estuarine plants and animals live at or near the limits of their tolerances (Malins, 1977a). In this stressful environment, species diversity is more limited than that in more stable environments. However, the estuarine ecosystem is highly productive, with large numbers of individual animals. Total biomass is relatively high (McLusky, 1981). Within an estuary, wetlands are an important feature. They provide shelter, specialized habitat, and most importantly, they are a source of energy to estuarine consumers (Malins, 1977a).

Oil in the estuarine environment is not a uniform or stable pollutant. Crude oil behaves differently and has different environmental effects from refined products. Also, the composition of crude oil varies greatly from field to field. As soon as oil is released in water, it undergoes weathering processes such as spreading, evaporation, emulsification, photo- and chemical oxidation, biological degradation, and agglomeration and sinking. Of these processes, biodegradation is particularly important in wetlands and estuaries because of the actions of bacteria, which are more abundant in these areas than in marine waters (Lee, 1977). The rate of weathering processes generally

increases with increasing ambient temperature. These processes can change the initial oil slick to suspend droplets, mousse, or tarballs (Royal Commission on Environmental Pollution, 1981). Oil pollution causes both physical and toxic effects in plants and animals. Generally, the lighter hydrocarbons in oil are the most toxic but are also the first fractions to weather from oil. Weathering time varies from hours to weeks depending upon the molecular weight of the fraction. Thus, the effects of oil on estuaries and wetlands vary considerably with the type of oil encountered and the degree of weathering it has undergone.

Oil droplets will encounter suspended particulate material in estuaries and will become adsorbed on oleophilic particles and detritus and sink to the bottom. Tarballs may also sink to the bottom or become stranded along the estuarine shoreline along with floating oil and mousse. Exposed intertidal sandy or muddy substrate may be coated with floating oil, too. Depending upon the grain size of the substrate, oil may be absorbed, adsorbed, or refloated on rising tides. Generally, oil does not penetrate or adhere to finer-grained sediments. This was observed in the Metula and Urquiola oil spills (Ruby, 1977). Penetration of sediment can vary from a few inches to nearly 2 feet (Blumer et al., 1971).

Stranded and sunken oil continues to degrade, varying with climate, availability of oxygen, and microbial activity (Malins, 1977b). The persistence of spilled oil in estuaries and wetlands varies considerably. Oil tends to last longer and to degrade more slowly in low-energy, protected environments (Rashid, 1974). Wetlands and sheltered tidal flats are particularly vulnerable to the long lasting effects of oil (Ruby 1977; Hahn, 1977; Gundlach et al., 1981; Gundlach, 1980). Crude oil that was stranded in wetlands from the Metula oil spill in 1974 in the cool climate of the Straits of Magellan has remained nearly unchanged and may persist for 100 years (Gundlach, 1980). In contrast, crude oil from the 1978 Amoco Cadiz spill in marshes along the Brittany coast degraded noticeably during a 3-year period, and the surface of the tidal flats was free of oil in less than 1 year (Gundlach et al., 1981). For further comparison, a spill of No. 6 fuel oil in the Chesapeake Bay in 1976 was mostly gone in a single season (Hershner and Moore, 1977). Persistence of oil in estuarine open waters and exposed tidal flats is less than in wetlands, but longer than in high-energy beaches and coasts. In the Amoco Cadiz spill, Metula spill, Torrey Canyon spill in England, and the Urquiola Spill in Spain, oil was gone from surface waters and most intertidal beds within 1 year (Ruby, 1977; Gundlach et al., 1981; Adams et al., 1984; Gundlach et al., 1978; Smith, 1970). However, residence time of oil absorbed into benthic substrates has been observed to last as long as 7 years (Blumer et al., 1971; Gundlach et al., 1981; Hayes, Gundlach, and Getter, 1980).

Estuarine biota are affected by oil through physical effects and toxic effects. The physical effects include coating of plants and animals so that respiratory and feeding structures are fouled, and smothering or starvation occurs. Substrate may be coated by oil so that oxygen cannot reach the root systems of vascular plants, or substrate may be fouled so that plants and animals can no longer utilize or colonize it. Oil coating will kill green leaves of wetland plants by blocking out sunlight or through toxic effects as

has been observed in mangroves (Odum and Johannes, 1975). Oil floating in shallow water cuts off sunlight to vascular plants and algae, and its lower albedo may raise water temperature and reduce dissolved oxygen (Odum and Johannes, 1975).

The toxic effects of oil can be lethal or sublethal. Cell death and animal mortality may result in lower animals. Higher animals may receive skin burns from contact with oil or may suffer various organ and glandular necroses resulting in death. Sublethal effects include reduced growth, altered feeding behavior, altered reproductive behavior, and lower reproductive success.

Within the estuary, adult and juvenile fish can generally sense oil and are mobile enough to avoid contact with it (Royal Commission on Environmental Pollution, 1981). However, planktonic fish eggs and fish larvae are highly sensitive to even small quantities of oil and may be killed by concentrations as low as 10^{-5} ml/liter of very toxic hydrocarbons (Perkins, 1974). Because of the number of variables involved, it is impossible to predict expected hydrocarbon levels in an estuary that might result from a large oil spill, but it would be expected to be higher than 10^{-5} ml/liter. Spawning and migration behavior may be affected in fish. Salmon have been observed to avoid oil-contaminated water. In open water, this is advantageous; but when the oil is in estuaries and streams, spawning salmon may be disrupted; and lower escapements result (Minerals Management Service, 1984).

Benthic plants and animals are highly sensitive to toxic hydrocarbons as in fresh crude and refined oil products, but responses of species to weathered oil vary. Some algae-grazing winkles, limpets, and chitons are killed by fresh crude but can be unaffected even though completely covered with weathered oil (Nelson-Smith, 1973). Likewise, the mortality rates in many bivalves and marine worms vary considerably with the species and the type of oil contacted. However, other grazing mollusks, like abalone, have a high mortality response to oil pollution (Nelson-Smith, 1973). Echinoderms, such as urchins and starfish, are also very sensitive to any oil pollution. Filter feeding animals, such as oysters, clams, mussels, and barnacles, may ingest oil-coated detritus, but effects vary with the toxicity of the oil. Some mollusks smothered with weathered oil have metabolized the oil and survived (Royal Commission on Environmental Pollution, 1981). Crustaceans, such as crabs and lobsters, are highly mobile and can avoid contact with small quantities of oil, although some affinity for kerosene has been observed in lobsters (Royal Commission on Environmental Pollution, 1981). However, contact with toxic hydrocarbons is fatal to many crustaceans. Larval forms of benthic invertebrates are all highly sensitive to oil, and some, such as crab larvae that float near the surface, are particularly susceptible to contact.

The responses of aquatic plants to oil pollution vary between species and with different types of oil. Some macroalgae, suck as kelp and other brown algae, are covered with mucilagenous slimes that keep them from being covered with oil, but they are sensitive to contact with toxic, light hydrocarbons. In contrast, red algae and many sea grasses are sensitive to any oil pollution (Nelson-Smith, 1973). Blue-green microalgae that cover intertidal mudflats are oleophilic and easily smothered by oil (Royal Commission on Environmental Pollution, 1981).

Oil pollution in salt marshes has been well studied (Baker, 1971). Important factors which affect damage to marshes are the amount and type of oil, plant species, time of year, and cleanup treatment. Single, moderate-sized oil spills have marginal effects on wetland plants (Hershner and Moore, 1977; Baker, 1971). However, multiple spills or large spills can destroy most or all emergent growth (Hayes et al., 1980). Generally, fresh oil has been observed to be more toxic than weathered oil to marsh plants (Baker, 1971). However, one study has shown that the immediate effects of spilled oil on Spartina marsh were the same for fresh as weathered oil (Bender et al., 1977). Plants with well-developed root systems such as Spartina store food better than shallow rooted and succulent marsh plants like Salicornia and Suada; though emergent growth may be destroyed, plants with rhizomes can send off new shoots. Oil pollution contact during the growing season can produce high seed and seedling mortality and can destroy flowers. Tropical mangrove swamps are also very sensitive to oil. Contamination of leaves, prop roots, and pneumatophores can be lethal to mangroves (Odum and Johannes, 1975; Chan, 1977a; Gundlach and Hayes, 1978).

Because oil can become stranded in marsh wetlands, it is incorporated into the marsh substrate and can inhibit new growth of plants and recolonization by intertidal invertebrates. Spartina marsh can begin regrowth after oil damage very shortly after the incident or during the following growth season (Hershner and Moore, 1977; Bender et al., 1977), while Salicornia and Suada may require several years to begin regrowth (Grundlach, 1980). Mangroves show continued die-off due to contaminated substrate several years after the initial oil spill (Chan, 1977a).

Cleaning up estuaries is a dilemma. Chemical dispersants and emulsifiers are toxic, and dispersed or emulsified oil may be more of a hazard than the oil slick (Nelson-Smith, 1973). Gundlach et al. (1978), and Smith (1970) proposed that some intertidal invertebrates were killed by cleanup efforts used in the Torrey Canyon and Urquiola spills. Physical sinking of oil in estuaries is undesirable because of potential benthic impacts, and combustion could cause property damage or air quality problems in populated areas. Sorbent material uptake of oil is the least damaging method (Little, 1970). Emulsifying agents are equally toxic to marsh plants (Baker, 1971). Cutting and burning have been used with equal success. Marsh recovery from cutting and burning has been about the same as in untreated areas because new growth is initiated from rhizomes. Sometimes, excessive trampling of the marsh in the act of cleanup can be more harmful than the untreated oil.

Recovery in estuaries and wetlands has been monitored after a number of oil spills. Depending upon the extent of damage, many plants and animals can begin recolonization immediately. In some cases, biomass has recovered within months to 2 years; however, changes in species composition and diversity have resulted, reducing ecological stability of the estuary and wetlands (Nelson-Smith, 1973). In some instances, total wetland productivity actually increased following recovery even though the community structure of the marsh was altered and the individual marsh species (Spartina) was a dwarf form (Hershner and Moore, 1977). In the Amoco Cadiz spill, marsh recovery took from 1 to 4 years (Gundlach et al., 1981), while recovery time of wetlands in the Metula spill may be measured in decades (Gundlach, 1980). Though recovery

times are variable, wetlands are considered to have relatively long recovery times compared with other coastal habitats (Adams et al., 1984; Gundlach and Hayes, 1978).

The time it takes for estuarine recovery following an oil spill varies and also may result in changes in species composition and abundance. Recovery times have been estimated at 8 to 10 years for Alaska (Ruby, 1977), to a few years for areas in temperate climates (Adams et al., 1984; Hershner and Moore, 1977; Chan, 1977b). Contamination of benthic substrate is a major factor in influencing recovery (Blumer et al., 1971; Hayes et al., 1980). In areas where natural diversity is low due to environmental stress, a pollution event can have dramatic impacts on estuarine ecosystems and ecotones.

Because of the habitats they contain and their relatively high productivity, estuaries and wetlands are important parts of the marine environment. On any scale of relative environmental sensitivity to oil pollution, estuaries and wetlands rank very high in comparison to other coastal ecosystems (Adams et al., 1984; Michel, Hayes, and Brown, 1978).

Beaches

Beaches and rocky shores are the most extensive shoreline habitats in most of the Outer Continental Shelf planning areas. Exceptions are the Central Gulf of Mexico, Gulf of Alaska, Kodiak, Cook Inlet, Shumagin, St. Matthew-Hall Basin, and Norton Basin planning areas where wetlands, including marshes, bays, and estuaries, are the dominant shoreline habitats. The extent of damage from oil spills on coastal habitats depends largely upon the residence time of oil in or on the habitat. The abundance, diversity, and sensitivity of the biota to oil, and the amount of weathering and physical characteristics of the oil are also important factors in determining the extent and severity of habitat damage. The sensitivity of intertidal fauna to oil is relatively well understood especially for macroinvertebrates of commercial interest. However, little is known about oil effects on macroalgae which may be abundant in rocky intertidal areas (National Research Council, 1985).

In all of the shoreline oil spill sensitivity indices, exposed sandy beaches and rocky shores are ranked relatively low in sensitivity. Oil retention on sandy beaches and rocky shores is short in comparison with retention on sheltered lagoons, tidal flats, marshes, wetlands, bays, and estuaries. Studies of No. 2 oil spilled at West Falmouth, Massachusetts, indicated that the effects of the oil were detectable in the sheltered salt marsh for at least 7 years (Krebs and Burns, 1977). However, oil was more rapidly removed from exposed beaches and rocky shores by waves, winds, and currents. Kolpack (1971) reported that exposed rocks that had been coated with crude oil following the January 1969 Santa Barbara Channel oil spill were free of oil within 3 weeks. A large amount of Santa Barbara crude oil and the straw that had been spread for cleanup purposes remained in the upper intertidal zone of East Cabrillo Beach 18 months after the spill. Only very small patches of the oil-straw residue were found nearly 2 years after the spill in the most sheltered sections of the East Cabrillo Beach study area (Nicholson and Cimberg, 1971). Damage to biota was generally through coating or smothering. There are distinct levels of sensitivity within this shoreline type. In

general, exposed, rocky cliffs are the least sensitive to oil spills. Damage is usually minimal because waves, winds, and currents remove oil rapidly, and is usually low (Hayes et al., 1980). Cleanup of exposed rocky shores is usually not required because of the rapid removal by natural forces. Flat, fine-grained, sand beaches that are exposed to significant wave energy are also very low in sensitivity to spilled oil. Fine-grained sand inhibits oil penetration, and oil burial depth is minimal. In cases of extensive contamination, cleanup is accomplished generally through the use of heavy equipment, such as earthmovers. Manual recovery techniques, such as spreading of chopped straw and shoveling, may be employed if the beach is inaccessible to heavy equipment or if the cleanup operations are in a final stage. Damage due to these cleanup techniques is not as great on fine-grained sandy beached as on medium- to coarse-grained beaches. The hard packing of fine-sand beaches simplifies cleanup. Oil burial and penetration are much greater on medium- to coarse-grained beaches. As a consequence of the loosely packed sediments, cleanup operations tend to force oil into the beach (Hayes et al., 1980). Mixed sand and gravel beaches may experience rapid oil penetration to 30 cm. (Hayes et al., 1980). As a result, retention time of oil in these beaches is relatively high, and cleanup is difficult without causing beach erosion. Within the beach/rocky shore habitat type, gravel beaches have a relatively long oil retention time and high sensitivity to spilled oil. Gravel beaches allow rapid oil penetration to 60 cm depth (Hayes et al., 1980). Study of a gravel beach at the Amoco Cadiz oil spill site demonstrated that oil persisted as a fresh mousse 8 months after the spill (Hayes, Gundlach, and D'Orouville, 1979). The long oil retention time results in contamination of the neighboring shoreline environments and the water column. Cleanup on gravel beaches may be accomplished by flushing with high or low pressure water streams (Woodward-Clyde Consultants, 1982). This activity causes high mortality of resident organisms. However, biomass is usually very low in such environments (Hayes et al., 1980).

Sheltered rocky shores are highly sensitive to oil contamination. Spilled oil coats the rough surfaces, and because wave energy is low, the oil may persist from months to years (Hayes et al., 1980). The resident biota may be diverse and abundant, and destruction or significant damage is likely to be caused by the oil and any cleanup. On rocky shores, recovery of intertidal communities to a pre-oil spill condition will depend upon the vertical level of the intertidal zone impacted (Murray and Littler, 1979). The upper barnacle zone normally requires the least time to recover (about 1 year) while the more structurally complex middle and lower levels require longer recovery times.

In general, recovery of rocky intertidal communities should begin within 1 year, and reproductive maturity should be attained within 5 years (Minerals Management Service, 1984).

In summary, sandy beaches and rocky shores are lower in sensitivity to spilled oil than marshes, wetlands, tidal flats, bays, estuaries, and lagoons. Oil retention time, as well as abundance, diversity, and biomass of biota, is generally low on sandy beaches and exposed rocky shores. Within the beaches/rocky shores habitat type, degrees of sensitivity to oil spills exist, with protected rocky shores exhibiting the highest level of sensitivity.

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Sensitivity of Marine Habitats to Oil Spills

The sensitivity of marine habitats (other than mud/sand bottoms) to spilled oil is discussed in the following sections. The major portion of each planning area consists of mud/sand bottoms which have a low sensitivity to spilled oil. The specific marine habitats discussed are submerged aquatic vegetation, submarine canyons, the shelf break zone, coral reefs, and live hard bottoms. The information summarized in the following discussions was used in calculating the relative environmental sensitivity of the OCS planning areas to spilled oil. Most of these marine habitats are generally too deep to receive large quantities of oil from the ocean's surface. The principal areas of sensitivity are shallow habitats such as beds of aquatic vegetation and coral reefs. The highly sensitive coral reefs, which occur only in the South Atlantic and Gulf of Mexico planning areas, do not occupy sufficient area to affect the sensitivity ratings significantly. Live hard bottom habitats may be sensitive in shallow areas, but information on the areal and depth distribution of these habitats is not available for most OCS planning areas. As a result of the low sensitivity of most marine habitats in the OCS planning areas, the sensitivity ratings for these habitats are lower than those for coastal habitats and marine biota.

Submerged Aquatic Vegetation

There are rooted seagrass beds as well as accumulations of macroalgae and microalgae forms in most of the subtidal, coastal portions of OCS planning areas. The seaward extent of their distribution is limited by the penetration of sufficient sunlight to support photosynthesis. Their abundance and distribution ranges from the estimated 3.7 million acres of seagrass beds in the Gulf of Mexico, 90 percent of which are off the coast of Florida, to the epontic algae forms which are found growing under ice in Alaska. There are also sparse assemblages of macrophytic algae distributed in the Arctic waters of Alaska (Minerals Management Service, 1983; Minerals Management Service, 1984a). These plants all play an important role in the productivity of the oceans. Their organic productivity is generally high and may actually exceed the production of intensively farmed agricultural crops. For example, productivity estimates for California kelp range from 3,000 to 22,000 grams/square meter. Their decomposition into detritus provides an important source of organic matter for the food web in the area. They also provide a substrate and habitat for many invertebrate and vertebrate animals, which in turn are eaten by other predators. Seagrass beds provide breeding, nursery, and feeding areas for a wide variety of commercially important shellfish and finfish (Minerals Management Service, 1983). Ice algae forms account for 25 to 30 percent of the primary production in areas of the Beaufort Sea (Minerals Management Service, 1984b). The effects of oil spills on true marine, subtidal forms are relatively unstudied. An assessment of effects on seagrass beds has been largely extrapolated from studies of intertidal and emergent plant forms found in coastal marshes and wetlands. The most severe impacts would occur in shallow (up to several meters) coastal areas where oil could come in close contact with the vegetation in an undiluted form. While most seagrasses and algae are resistant to oil contamination, repeated applications will destroy the root and rhizome systems and denude the area (Thomas, 1979).

In heavy applications of oil, algae may become bleached and lose fronds. Oil and tar may adhere to shallow forms and tear the algae away from its point of attachment through wave action. Ironically, very light oiling may actually enhance growth in certain forms (Thomas, 1979). Damage to plants would also be greater during the active growing periods in the spring and summer (Minerals Management Service, 1984a). The effects on shallow vegetation, therefore, can be extensive and may require 1 to 3 years to recover from an oil spill incident (O'Neil et al., 1983).

Deep water forms of aquatic vegetation would probably not be as severely affected. The probability of oil being incorporated into the water column and transported to extensively vegetated areas is unlikely. In addition, the oil would be diluted and widely dispersed. Contact with oil, therefore, would be transient in nature. (Minerals Management Service, 1983). The use of dispersants in oil spill cleanup operations should further dilute oil, and should result in reduced toxicity to aquatic vegetation, assuming low toxicity dispersants are employed. Mechanical removal techniques should only impact shallow communities and should not exceed damage caused by direct oiling (Thomas, 1979).

Submarine Canyons

Submarine canyons are natural features of the world's continental shelves and slopes. Most were formed by river and stream erosion in the geologic past when the shelf was a terrestrial feature, although some have been formed by faulting and erosional bottom currents (Heezen, 1978). On the U.S. continental margin, the largest concentration of canyons is found in the Mid- and North Atlantic, where more than 70 named and hundreds of unnamed canyons are located (Hecker et al., 1983). The Gulf of Mexico contains three major canyon systems, California has isolated canyons throughout the shelf, and the Alaskan shelf has numerous canyons primarily in the Gulf of Alaska and the Bering Sea.

Most canyons occur at the shelf edge, incising both the shelf and continental slope. Topography and physical forces interact in many canyons to create and maintain a habitat that can be quite different from the surrounding lower-relief bottom. Bottom-dwelling organisms in canyons are distributed patchily but represent a more diverse assemblage than those found on the surrounding slope and rise in the North and Mid-Atlantic (Hecker et al., 1983). The Atlantic canyons are important habitats for lobster, red crab, squid, marlin, tilefish, and swordfish. Other species, such as deep-water corals, that require a hard substrate for attachment, occur in greater abundance and diversity in canyons where more hard substrate is found than on the adjoining slope (Hecker, 1983).

Canyons are natural conduits between the continental shelf and the continental rise for water, suspended material, and nutrients. Tidal currents and other water mass movements move materials both up and down the axes of canyons, resuspend sediment from the floors of canyons, and occasionally retain materials for significant, but as yet undefined, periods of time (Butman et al., 1982). Canyon heads are probable entry points for natural and pollutant materials from the continental shelf (Hecker et al., 1983).

Materials such as oil or drilling fluids discharged in or near canyon heads could move into the canyons and be retained there for some period of time that might prove deleterious to indigenous biological resources. This phenomenon has not been observed for discharged drill fluids, which are the only pollutants studied systematically. However, some oil could enter canyons through adsorption onto particulate matter such as drill mud clay particles. During the Georges Bank Monitoring Program, a sediment trap located in Lydonia Canyon was examined for barium content from drilling discharges from Sale 42 (North Atlantic) leases. Evidence of accumulation of these materials was not found in Lydonia Canyon, located approximately 10 miles SSE of one drilling operation (Block 312) and 25 miles east of another (Block 410) (Bothner, 1983). However, Bothner (1983) also demonstrated increases in sedimentary barium concentrations as far as 40 miles to the west of these same operations. Local hydrographic conditions determine deposition, and conditions in canyons may not be conducive to entrapment and accumulation.

Direct effects of spilled oil on deep submerged features such as canyons have not been studied systematically in the field. However, significant adverse direct effects are not anticipated. Freshly spilled oil rises to or floats at the ocean's surface where forces of dispersion and dissipation begin acting immediately. Oil spreads and evaporation to the atmosphere rapidly removes the more volatile, toxic components. Dissolution into surface waters and continued dispersion by winds, waves, and currents operate to reduce the spill further. The National Academy of Sciences (1975) estimated that 75 to 80 percent of an oil spill is removed by these various weathering processes before the final products of a spill are formed. The visible final products are generally referred to as "tar balls," bits of tar that remain at or near the surface and are transported by winds and currents. The density of most weathered oil does not become great enough for neutral buoyancy to occur (NRC, 1985), which means, in most cases, that tar balls do not sink. The NRC (1985) notes four important sedimentation mechanisms by which petroleum can reach sediments: 1) sorption of oil by suspended particles such as clay and detritus; 2) ingestion of oil by zooplankton and incorporation into fecal pellets; 3) weathering of oil by physical/chemical processes; and 4) direct mixing of oil and sediments. The first two mechanisms are probably the most important as far as potential impact to submarine canyons, but cumulatively they would only account for a small portion of the spill reaching bottom in deeper water. Given upon ocean conditions, the average depth of canyons, physical dispersion of these materials, and chemical and biological transformations, there is a low likelihood of impact to canyons and canyon fauna.

As little is known of the possible effects of an oil spill on canyons, the potential for habitat recovery from such an event is also little known. It is known that canyons are dynamic environments that would presumably aid recovery. Recovery could not be aided by cleanup intervention, as technology for deep water cleanup has not been developed and would be prohibitively destructive and expensive.

The Shelf Break Zone

The continental margin (submerged land from the coastline to the deep ocean) consists of two primary features, the continental shelf and the continental slope. These physiographic features are generally delineated by steepness; the shelf is the area of nearly flat terrain that extends from shore to the shelf/slope break where steepness markedly increases. The steeper bottom that extends down to the continental rise and abyssal depths is the continental slope. The break is generally considered to occur at 200 meters, although by the steepness criterion, the break can occur anywhere from 20 to 400 meters. In relation to the shoreline, the shelf/slope break may be found immediately offshore, or be located hundreds of miles from shore. On the U.S. continental shelf, the Atlantic Region has an average shelf width of 40 miles, the Gulf of Mexico has an average width of 60 miles, the Pacific Region has a narrower shelf, and Alaska varies from a 100 mile shelf in the Gulf of Alaska to broad shelves of several hundred miles in the Bering and Beaufort regions (Alaska Department of Community and Regional Affairs, 1976). The break was created and maintained over geologic time by a combination of lower sea level during Pleistocene times, uplift, subsidence, faulting, slumping, and erosional currents (Heezen, 1978).

The shelf break zone is a transition zone of biologic and non-biologic parameters from shallower shelf conditions and communities to deep water conditions. Non-biologic parameters such as light, temperature, and pressure change dramatically as depth increases rapidly beyond the break. Bottom sediments and organisms become less and less affected by such surface phenomena as atmospheric temperature, winds, and storms, phenomena that are extremely important in determining the fate of an oil spill. Biological communities also represent a transition zone to deeper communities that are adapted to less or no light, greater pressure, and lower energy current regimes.

The shelf break zone is also the area where many of the topographic and physiographic features discussed elsewhere are found. The numerous Atlantic canyons, as well as many canyons elsewhere, typically cut through the shelf break zone. Many of the topographic rises (fishing banks, Flower Gardens reefs) in the Gulf of Mexico are located near the edge of the continental shelf. Deep troughs and valleys parallel the break in many areas; seamounts are located in deep waters in the Gulf of Alaska relatively close to the shelf/slope break.

The shelf break zone, as a transition zone between shallow and deep water environments, is a virtually continuous and extensive feature of the world's oceans. Biologic composition of transition zone communities, as with shallow and deep water communities, varies with latitude, but this variation is also gradual without abrupt discontinuance based solely on latitude.

Direct effects of spilled oil on deeper submerged features such as the shelf break zone have not been well studied in the field. The typical behavior of spilled oil, however, would mitigate against serious effects.

Spilled oil from whatever source is assumed to rise to or stay on or near the ocean surface, where forces of dispersion and dissipation begin acting immediately. Oil spreads and evaporation to the atmosphere rapidly removes the more toxic volatile components. Dissolution into surface waters and continued dispersion by winds, waves and currents operate to reduce the spill further. It has been estimated (National Academy of Sciences, 1975) that as much as 75 to 80 percent of a given spill is removed by the various weathering processes before the final products of a spill are formed. The visible final products are generally referred to as "tar balls," bits of tar that remain at or near the surface and are transported by wind and water movements. The density of most weathered oil does not become great enough for neutral buoyancy to occur (NRC, 1985), which means, in most cases, that tar balls do not sink. The NRC (1985) notes four important sedimentation mechanisms by which petroleum can reach sediments: 1) sorption of oil by suspended particles such as clay and detritus; 2) ingestion of oil by zooplankton and incorporation into fecal pellets; 3) weathering of oil by physical/chemical processes; and 4) direct mixing of oil and sediments. The first two mechanisms are probably the most important as far as potential impact to the shelf break zone, but cumulatively they would only account for a small portion of the spill reaching bottom in deeper water. Given open ocean conditions, the average depth of the shelf break zone, physical dispersion of these materials, and chemical and biological transformations, there is a low likelihood of impact to the shelf break zone and its associated fauna.

Just as little is known of possible direct and indirect effects of an oil spill on the shelf break zone, the potential for habitat recovery is also little known. The habitat and fauna are less affected by surface phenomena and thus less energy is imparted to them, but it can be a dynamic environment nevertheless. Recovery potential would be basically the same in most areas, with areas of colder bottom water and less current energy being somewhat slower to recover. Recovery could not be aided by cleanup intervention, except insofar as surface cleanup reduces the amount of material that could reach bottom. Surface cleanup would not damage shelf break habitats or biotic resources.

Coral Reefs

The only true flourishing tropical coral reefs on the U.S. continental shelf are found in the Dry Tortugas, along the Atlantic side of the Florida Keys northward to near Miami, and at the East and West Flower Gardens in the northwestern Gulf of Mexico. Coral reefs are dominated by hermatypic (reef-building) corals and coralline algae that are restricted in their distribution by light and temperature. There are many other types of corals (stony, alcyonarians) that do not build reefs that are found throughout the world's oceans. Concentrations of hermatypic and non-hermatypic corals are found in many locations in the Gulf of Mexico and South Atlantic, but true tropical coral reefs are only found at the locations noted above. The Florida Keys and Tortugas reefs are shallow reef communities (3 to 6 meters) dominated by branching coral species, while the Flower Garden reefs are deep-water structures (15 to 52 meters) dominated by coral head species and where no branching species are found (Bright et al., 1983).

Corals of various types are known to be affected by oil, both crude and refined, and by dispersants sometimes used in cleanup operations (Connell and Miller, 1980). Different species have different latency periods during which there appears to be no response to the initial contact with oil. This latency is attributed to the ability of live coral to secrete a protective mucus when stressed (Reimer, 1975). After the latency period, the variability of type and duration of response is quite wide. Responses to contact with oil or oil in water mixtures include polyp retraction or extension, tissue rupture, zooxanthellae (symbiotic algae) expulsion, reduced feeding activity and growth, loss of color and mortality. The NRC (1985) summarized some of the more recent work on responses of coral to oil, in addition to the types of responses noted above. Oiled reefs exhibited smaller numbers of breeding colonies, a decrease in the average number of ovaria per polyp, smaller numbers of planula larvae produced per coral head, and a lower settlement rate of planulae on artificial substrates. Extrapolation of results to field conditions, and comparison of field studies is severely hampered, according to the NRC report, by a lack of reliable information on the actual concentrations or composition of oil in the water near the reefs, as well as a poor understanding of reproductive physiology and metabolism of reef corals.

Many of these responses above are elicited by exposure to an oil in water mixture with a concentration in the 100 ppm to 500 ppm range (Lewis, 1971). Field studies in the Persian Gulf (Shinn, 1972; Spooner, 1970) have indicated, however, that reefal systems seem to have suffered little in areas of chronic oil pollution from natural seeps and transportation. The Flower Gardens themselves have been the subjects of a multi-year characterization and monitoring study conducted by the Texas A & M Research Foundation. To date, no deleterious effects of intensive nearby exploration and development have been observed on the coral reef cap or surrounding coralline algae apron (Texas A & M Research Foundation, 1983). The methodology used by Texas A & M and the statistical ability to detect anything other than massive coral mortality has recently been questioned (Clement Associates, 1984), although this study focused on potential effects of drilling muds. Deeper reefs like the Flower Gardens are more likely to be insulated from spilled oil than shallow reefs such as the Keys; a depth related effect to surface oil (decreased response with increased depth) has been observed by Cohen, Nissenbaum, and Fisler (1977).

Recovery potential of corals exposed to oil appears to be quite high, at least in laboratory and field tests of short term recovery after an exposure. Several investigators (Elgershuizen and De Kruijf, 1976; Grant, 1970; Coles and Maragos, 1972; Shinn, 1972) have noted that various coral species apparently recover completely from short term oil exposure once the exposure ceases and the corals are reintroduced to uncontaminated seawater. These authors also note that these were modestly gross appraisals, that sublethal effects may have occurred that were not observed, and that longer-term exposures to low-level concentrations of petroleum may have different results. Little work has been done on these aspects of the problem.

Some work has been done on one aspect of cleanup as it relates to coral. In cases of coral recovery noted above, the recovery was natural in that it occurred with re-exposure of the corals to uncontaminated seawater.

Elgershuizen and De Kruijf (1976) ran toxicity tests of petroleum and certain oil dispersants on a stony coral species. Mixtures of dispersants and oil increased the toxicity of both considerably. These authors concluded that oil is dangerous for reef ecology, but chemical cleanup procedures may expose reefs to greater dangers.

Live Hard Bottoms

"Live" bottom areas are defined as areas containing "biological assemblages consisting of such sessile invertebrates as sea fans, sea whips, hydroids, anemones, ascidians, sponges, bryozoans, or corals living upon and attached to naturally occurring hard or rocky formations with rough, broken, or smooth topography, or whose lithotope favors the accumulation of turtles, fishes, and other fauna" (South Carolina Marine Resources Research Institute, 1981). The terms "live bottom" and "hard bottom" have been used somewhat interchangeably, but for clarification, a live bottom habitat must have hard bottom substrates to provide for attachment of organisms and development of a live bottom community, whereas hard bottom areas are not necessarily live bottoms. Live bottom communities found in the Gulf of Mexico and the South Atlantic are typically composed of species commonly found in tropical coral reefs, and as such are limited in their northern extent on the U.S. continental shelf to sub-tropical and temperate zones. Live bottoms are distinguished from coral reefs by the absence or near absence of hermatypic (reef-building) coral species, although other types of coral may be present. Significant live bottom habitats on the U.S. shelf are found in the South Atlantic off the coasts of North and South Carolina, Georgia and northern Florida, in the Gulf of Mexico on the numerous hard banks in the central and western regions and at the Florida Middle Grounds off northern Florida, and on hard banks and rises off the coast of Southern California. There is abundant geophysical evidence that extensive hard bottom habitats also exist offshore Central and Northern California. There is a high probability that these habitats contain live bottoms.

Biotic diversity in live bottom communities is clearly higher than surrounding soft-bottom clay or sand habitats, but almost never as high as tropical coral reef communities (Bright, 1983). South Carolina Marine Resources Research Institute (1981) and Texas A & M Research Foundation (1983) both recognize live bottom habitats in three bathymetric zones: nearshore or inner shelf, mid-shelf, and outer shelf which includes the shelf-slope break. Depths used to characterize these zones are different in the Gulf than in the Atlantic, with inner shelf live bottoms occurring shallower in the Gulf than in the South Atlantic. South Atlantic studies utilize 19-27m in depth for inner shelf, 28-55m for middle shelf, and 56-100m for outer shelf. Depth of habitat is an important consideration in assessing the vulnerability of a habitat to oil spills, due to the inherent behavior of spilled oil to rise to, or remain near, the sea surface.

Little experimental work has been done on the effects of oil spills on high diversity live bottom communities, either in controlled field or laboratory conditions or during accidental oil spills. Due to the similarities of these communities to coral reef communities, some limited information on effects and

recovery of reefs may be extrapolated to live bottom communities. Coral responds to oil or oil in water mixtures by mucus secretion, polyp retraction or extension, tissue rupture, zooxanthellae expulsion, reduced feeding activity and growth, and loss of color and mortality, depending on length and severity of exposure. Many of these responses are elicited by exposure to an oil in water mixture with a concentration in the 100 ppm to 500 ppm range (Lewis, 1971). Field studies in the Persian Gulf, however, have indicated that reefal systems seem to have suffered little in areas of chronic oil pollution from natural seeps and transportation (Spooner, 1970; Shinn, 1972). The Flower Garden reefs in the Gulf of Mexico have experienced no deleterious effects from intensive nearby oil and gas exploration and development (Texas A & M Research Foundation, 1983). Deeper reefs, and presumably live bottoms, are more likely to be insulated from spilled oil; a depth-related effect to surface oil (decreased response with increased depth) has been observed by Cohen, et al. (1977).

Recovery potential of coral appears to be high, at least to short-term exposure to oil followed by reintroduction to uncontaminated seawater (Grant, 1970; Shinn, 1972; Coles and Maragos, 1972; Elgershuizen and De Kruijf, 1976). These investigators noted that sublethal effects and effects from long-term low level exposure were unknown, except for the Persian Gulf observations noted above. Toxicity of spilled oil seems to be increased with the use of certain chemical oil dispersants (Elgershuizen and De Kruijf, 1976); live bottoms would presumably be more susceptible if these dispersants were used in cleanup operations. However, advances are being made in decreasing the toxicity of dispersants.

Live bottom areas would be severely stressed by direct contact with spilled oil. The depths where these habitats are found, however, serve to protect them against long-term direct contact with spilled oil. Sublethal effects and effects from long-term low level oil contamination are not known at present.

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Sensitivity of Biota to Oil Spills

The sensitivity of various groups of biota to spilled oil is discussed in the following sections. The information provided in these discussions was used in calculating the relative environmental sensitivity of the OCS planning areas to spilled oil. A similar evaluation was performed for the 1982 analysis of environmental sensitivity. However, the information from that evaluation was not joined with the results of the habitat analyses. In this way, the 1982 analysis avoided redundancy. The present analysis incorporates the redundancy between habitats and biota. This incorporation provides a more complete understanding of the sensitivity of each planning area than that provided by the 1982 analysis. The overall sensitivity of each OCS planning area is a combination of the sensitivities of the habitats and biota which occur within its boundaries.

Plankton

Phytoplankton (microscopic plants) and zooplankton (microscopic animals) lack means of avoidance and are vulnerable to floating oil as well as the dissolved and entrained oil beneath the ocean surface. Individual plankton may be affected by toxic reactions to components of the oil or by physical coating which impairs the exchange of gases (Hyland and Schneider, 1976). Additionally, zooplankton ingest oil. Some copepods and barnacle larvae do not distinguish between food particles and oil droplets and ingest either as the opportunity arises (Parker, Freegarde, and Hatchard, 1971). As much as 10 percent of the oil (bunker C) released from the wreck of the Arrow was associated with feces of the zooplankton. Seven percent of the weight of the feces was bunker C fuel oil. Conover (1971) estimated that in addition to normal sedimenting processes, 20 percent of the particulate oil was deposited as zooplankton feces.

The severity of effects of petroleum hydrocarbons on plankton is dependent on such factors as the species composition, season, temperature, light intensity, and on the concentration as well as the type of petroleum (Sanborn, 1977). Toxins from spilled oil reduce populations of all types of plankton (Royal Commission on Environmental Pollution, 1981). In general, unicellular algae are killed when toxic oil components are present in the water column in excess of 1 part per million (ppm) and cell division is retarded by exposure to concentrations exceeding 0.1 ppm. Sanborn (1977) reported the two periods when contamination by oil would be most critical for zooplankton are at the extrusion of gametes and at the time of metamorphosis and setting on benthic substrates.

Mironov (1969), Kunhold (1970), and Corner, Southward, and Southward (1968) reported that zooplankton larvae are 10 to 100 times more sensitive to oil than adults. While individual species' toxicities for eggs and larvae vary, a generally accepted toxicity threshold is 50 ppb (Kunhold, 1977; Kunhold et. al., 1978; Sanborn, 1977). Not only are eggs and larvae usually more sensitive to petroleum, but in many cases their period of exposure is lengthened because they float passively along with the spilled oil. This significantly increases the potential of extensive mortality. This effect is

mediated for many species, whose larval development results in vertical movement throughout the water column and descent to the bottom.

There is evidence that oil spills in open water have little more than a transient effect on plankton. Observations of the impact of the Torrey Canyon wreck are illustrative of available information. Although this spill occurred at a time when the zooplankton contained a large number of pilchard eggs and high mortality was observed, there was no detectable effect in the pilchard population in subsequent years (Royal Commission on Environmental Pollution, 1981). With exceptions, the recovery of phytoplankton and zooplankton communities, particularly in large bodies of water, is apparently rapid. These species are widely dispersed, reproduce rapidly, and grow quickly to maturity; and pre-spill population densities and/or stable age-distributions are soon restored (Hyland and Schneider, 1976). However, when a spill occurs in or impinges upon estuarine nursery grounds or other confined communities, such as those under ice, small localized breeding populations, especially the larval forms of some fish, or crustaceans and molluscs, may be severely affected, and complete recovery may take several years (Council on Environmental Quality, 1974; National Research Council, 1985).

Mud/Sand Benthos

Most studies at oil spill sites have examined the effects of petroleum on the intertidal communities. These communities have been the focus of study for several reasons. First, most spilled oil floats and contacts the intertidal zone. Oil deposited in the intertidal zone is visible from shore, and the intertidal environment is more easily accessible for study than subtidal habitats. Finally, the intertidal zone historically has been a primary area of study and, consequently, provides a much better baseline for determining effects of oil spills (Sanborn, 1977). For these reasons, effects of oil spills on the subtidal soft-bottom benthos have not been studied as thoroughly as those on intertidal communities.

Several mechanisms facilitate the transport of oil from the ocean's surface to bottom sediments. Weathering of oil results in increased density and sinking, adsorption of oil to suspended particulate matter results in sedimentation, and ingestion of oil by zooplankton with subsequent incorporation in fecal pellets also results in sedimentation of oil. Conover (1971) reported the presence of oil droplets in zooplankton feces in Chedabucto Bay following the Arrow spill in 1971. Significant levels of petroleum residues were also found in zooplankton fecal pellets in the Sargasso Sea (Sleeter and Butler, 1982). Hydrocarbons that are encapsulated in zooplankton feces are sedimented, but the ultimate fate of these hydrocarbons is unknown (Sleeter and Butler, 1982).

Impacts from oil spills on subtidal soft-bottom benthos generally are considered to be low (MMS, 1983a). This is especially true at increasing water depths where probability of impact is lower and weathering and dilution of the oil is greater (MMS, 1983a). The benthic fauna in the Santa Barbara Channel was studied following the oil spill from Platform A in 1969. No effects directly attributable to the oil spill were observed in the subtidal benthic fauna. Fauchald (1971) emphasized that this conclusion did not imply that the oil spill had no effects. It was not possible to separate effects

that the oil may have had on the soft-bottom benthos from other natural and anthropogenic factors.

A study of the IXTOC oil spill, funded by the Department of the Interior, compared community parameters at 12 stations in the Gulf of Mexico off the coast of Texas. The study compared soft-bottom community composition from samples collected 2 to 5 years before the oil spill to samples taken after oil from the IXTOC spill had been observed in the area. A principal conclusion of this study was that the temporal variations observed in the soft-bottom benthic communities could not be related definitely to the oil spill (ERCO, 1982).

A large spill of No. 5 fuel oil occurred when the tanker Tsesis grounded in the Baltic Sea off the coast of Sweden. Biological samples of the soft-bottom benthos from a depth of 30 m were collected following the spill. A significant reduction in total macrofauna abundance at one station was attributed to effects of the oil (Elmgren et al., 1980). The reduction in macrofauna was due primarily to the nearly total disappearance of two normally abundant species of amphipods and one species of polychaete. The investigators suggested that this reduction was due to emigration of these motile species. More sedentary organisms, such as clams, remained at normal abundances with no increase in mortality. Abundance of all meiofauna groups, except nematodes, was reduced, and high mortality of ostracods was reported.

In a study of the March 1978 Amoco Cadiz oil spill, Gundlach et al. (1983), determined that approximately 8 percent of the total oil lost was deposited in subtidal sediments. Much greater amounts of the spilled oil washed into the intertidal zone (28 percent) or evaporated (30 percent). Despite the low percentage of oil deposited on the subtidal benthos, numerous razor clams and heart urchins in shallow subtidal areas were killed during the first few weeks after the spill (Cross et. al., 1978). The residence time of oil in subtidal sediments varied with sediment type and physical energy of the area. Oil concentrations in areas with coarse-grained sediments and swift currents decreased by nearly 75 percent after 6 months, 90 percent after 18 months, and nearly 100 percent 30 months after the Amoco Cadiz spill. In areas with little physical energy and fine-grained sediments, oil persisted at high concentrations more than 3 years after the oil spill.

In summary, the soft-bottom benthos exhibits relatively low sensitivity to spilled oil in comparison to hard-bottom and intertidal communities. In many studies of oil effects on subtidal soft-bottom benthic communities, natural variability within the community is responsible for most observed changes in abundance and diversity of benthic populations, and effects cannot definitely be attributed to the oil spill as a primary cause.

Fish and Shellfish

The severity of the impact of spilled oil on fish and shellfish is a function of the size of the oil spill, the composition of the oil to which the fish are exposed, the duration of the exposure, and the life stage and season during

which the fish and shellfish are exposed. The physico-chemical characteristics of the oil and the duration of exposure are influenced by local hydrodynamic and meteorologic characteristics.

Fish might be more sensitive to short-term, acute exposures, in comparison to invertebrates according to the National Research Council (NRC, 1985). Rice et. al. (1979), observed that pelagic species of fish seem to be more tolerant than benthic species while fish inhabiting intertidal areas appear to be the most tolerant. Benthic species are of special concern because of their association with benthic sediments which would be the ultimate sink for spilled oil.

The effect of petroleum on the ecology of fishes, however, and most other marine life, is not completely understood. The following generalities are results based on the extensive research carried out at the organismic level.

1. Sensitivity of fish to oil generally diminishes from eggs to larvae to fry to adults. Eggs and larvae may die in spawning or nursery areas due to coating or direct toxic effects. Crude and bunker oils are toxic to fish eggs at concentrations of 1 ppm. Major behavioral abnormalities have been reported in larvae at concentrations of 0.0001 ppm.

2. Adults may be killed from direct toxic effects or indirectly as a result of maladaptive behavior. Behavioral changes may include loss of equilibrium, inability to school, and reduced swimming activity.

3. The reproductive output of adults may be affected.

Additional sublethal effects reported in studies of the effects of oil on fish include: histological damage, and physiological and metabolic perturbations. Because repair or recovery requires energy, these sublethal effects can lead to vulnerability to disease or to decreased growth and/or reproductive success. (National Research Council, 1985).

Mironov (1969), Kunhold (1977), Kunhold et. al. (1978), and Corner et al. (1976), reported fish larvae to be 10 to 100 times more sensitive to oil than adults. Individual species' toxicities for eggs and larvae vary, but the generally accepted toxicity threshold is 50 ppb (Kunhold, 1977; Kunhold et. al., 1978; Malins, 1977). Not only are eggs and larvae usually more sensitive to petroleum, but in many cases their period of exposure is lengthened because they float passively along with the spilled oil, resulting in the potential extensive mortality. This effect can be mediated for many species, whose larval development results in vertical movement through the water column and descent to the bottom.

Ebeling et. al. (1971), reported that fish may be less vulnerable to spills than any other groups of aquatic organisms because of their mobility and avoidance reactions. Nelson-Smith (1973) suggested that because large fish kills have not been reported following oil spills, one must presume that actively swimming fish avoid spills. However, groundfish are likely to experience extended exposures from oil which has been deposited in benthic sediments.

Numerous mortalities of benthic invertebrates have been reported (Hampson and Sanders, 1969; Sanders, 1981) when spilled oil contacts bottom communities. The predominant cause of death is smothering, but if the spill is fresh (less than 3 days old) the more toxic components may still be present and may contribute to mortality. Behavioral modifications and reduced reproductive capacity may also result from such exposures. Using a flow-through bioassay system with 0.25 ppm crude oil, Capuzzo (1982) observed that postlarval lobsters were less sensitive to crude oil-sea water mixtures than the larval stages. Disruptions in the energetics of larval development were observed, but the normal pattern of energy storage and utilization was slowly restored when the organisms were transferred to uncontaminated water. In a flow-through bioassay system using 50 ppb and 500 ppb Lago Medio crude oil, the bivalve Mya truncata did not display any behavioral stress response relative to that of the control (Mageau and Engelhardt, 1984).

The magnitude of impact from a spill is highly variable. Assessment of impact on a biological resource is most often based upon long-term effects to the population as a result of initial egg and larval mortalities. Species which rely heavily on one or a few successful year classes to supply the majority of the recruitment are particularly vulnerable to environmental perturbations, both natural and man induced, such as oil spills. If numerous sexually mature animals die from direct coating or toxicity, the size and reproductive potential of the population could be significantly reduced. Based on reported avoidance reactions, mortality to adult finfish is not expected to be significant.

Individual species may be more or less sensitive to spilled oil. Larval development rates and pathways vary; for example, herring have demersal eggs and planktonic larvae, whereas cod have planktonic eggs and demersal larvae, so that exposure to an oil spill will have different impacts on differing species at the time of an oil spill.

Where fishery resources are widespread, impacts from a spill are likely to affect only a small portion of the population. There exists no direct evidence that an oil spill has affected a stock as a result of mortality of eggs and larvae (Boesch et al., 1984). A large spill occurring during a critical recruitment period could seriously diminish recruitment to the stock for the year, particularly for those species in which eggs and larvae concentrate in the near-surface waters. For a species such as haddock in which only one year class of every five to ten contributes substantially to the fishery, the loss of a good year class could be disastrous; for other species, such as cod, in which the contributions of the different year classes are much more uniform, the effect on the stock would be much less important. Boesch et al. (1984), concluded that the probability of a significant effect on a stock occurring is low on the basis of the improbable coincidence of a critical recruitment period and a large spill resulting in toxic effects.

Because juvenile forms of many economically important species live in inshore environments, events there may affect those species even though offshore adult populations are not directly or immediately affected.

Marine Birds

Birds which spend most of their time on the surface of the sea and dive for their food are at greatest risk from oil spills (Royal Commission on Environmental Pollution, 1981). When birds encounter floating oil, their plumage becomes matted. Matting allows water to penetrate the air space between the feathers and the skin, and the birds lose buoyancy and drown. Oil also destroys the insulating layer, and the body loses heat. In colder climates the loss of heat is critical. In heavily oiled birds, the body responds by increasing its metabolism to approximately twice the normal rate. Severely oiled birds are unable to hunt for and catch food; this results in rapid emaciation and small chance for survival. Even light oiling causes an increase in weight and affects the aerodynamic properties of the wings. This impairs the ability of the bird to forage (Holmes and Cronshaw, 1977).

In addition to the problems caused by external coating by oil, sea birds ingest oil through preening and through consuming oil-contaminated food (Holmes and Cronshaw, 1977). This may lead to respiratory and intestinal irritation and damage to the liver and kidneys (Royal Commission on Environmental Pollution, 1981). Holmes and Cronshaw (1977) reported that ducks which had been fed oil-contaminated food suffered a higher mortality rate when exposed to lower temperatures than a control group.

Oil spills may interfere with the reproductive rate of marine birds. This is of concern because they often produce only one egg each season per pair (Royal Commission on Environmental Pollution, 1981). Oiled birds returning to the nests can contaminate the eggs. Coating of the eggs by petroleum reduces their hatchability (Holmes and Cronshaw, 1977). This reduced hatchability may result from impairment of gaseous exchange through the shell (Holmes and Cronshaw, 1977) and/or penetration of the shell by hydrocarbons with adverse effects on the embryo through systemic action (Albers, 1978).

There is no direct relationship between the amount of petroleum released in a spill and the number of birds killed. The known number of birds killed as a result of the 200,000 tons of oil released by the wreck of the Amoco Cadiz (4,572 birds) contrasts sharply with the death of 50,000 birds as a result of the discharge of 1,000 tons of fuel oil off northeast Britain (Holmes and Cronshaw, 1977; National Research Council, 1985).

The largest number of mortalities occur when oil spills encounter large concentrations of birds, especially in enclosed inlets or estuaries. Seabird population models (Wiens et al., 1979) project that recovery periods as long as 20 to 50 years may be required if breeding adults of groups such as alcids and storm petrels, which are characterized by very low reproduction rates, suffer substantial losses from a spill. A major oil spill coinciding with a period of high natural mortality, such as that caused by limited food resources, could substantially increase bird mortality and retard natural recovery of the population (Ford et al., 1982). Despite this potential for major impacts, Clark (1984) has concluded that mortality of seabirds from oil pollution does not, in general, appear to result in a detectable effect on seabird populations. In contrast, northern (Arctic) auk populations are already in serious decline from other forms of human interference, and

increased exposure to oil pollution is likely to affect them more seriously. Marine birds will be more affected by spilled oil in cold waters than in temperate waters due to the slower evaporation of the more volatile fractions. Oil frozen into the sea ice and released during thaw may further prolong the effects of a spill (National Research Council, 1985).

Although cleaning and rehabilitation of oiled birds is possible, only a very small proportion of marine birds can be rescued, rehabilitated, and returned to the sea (Royal Commission on Environmental Pollution, 1981). Clark (1984) reports that other methods are being used to reduce impacts of oil spills on marine birds. These include scaring the birds from the path of the spill, protecting sensitive areas with booms, chemical dispersion of the spill, increased regulation of shipping practices, and greater government control of the oil industry.

Coastal Birds

Coastal birds have the same sensitivity to contact with oil as marine birds. However, because of their various nesting, resting, and feeding habitats and behaviors, coastal birds as a group have a lower risk of exposure to oil pollution compared with marine birds (Perkins, 1974).

In addition to their use in flight, a bird's feathers provide insulation and buoyancy. The feathers and down trap air and are hydrophobic allowing the birds to swim and float without wetting or chilling. Feathers are also oleophilic so that oil is readily adsorbed and difficult to remove. Oil destroys the air holding structure of the feathers and down permitting water to reach the bird's skin. As a result, natural buoyancy and insulating properties of the feathers are lost (Hansen, 1981).

Birds succumb to physical contact with oil in a number of ways. Heavily oiled birds weighed down by oil can drown. The literature indicates that 50 to 90 percent of birds oiled in a spill never reach shore but drown and sink (Nelson-Smith, 1973). Hypothermia due to a loss of insulation is another cause of death. As a result, winter mortality rates for oiled birds are higher than those for summer or warm water, partially due to migration concentrations, but mostly due to temperature stress. Metabolism may double in an oiled bird as it tries to maintain body heat, and starvation can add to the bird's stress (Royal Commission on Environmental Pollution, 1981). Oiled birds that reach shore begin preening incessantly. This preening further destroys the structure of the feathers, and birds will not stop preening to eat. This preening behavior and accompanying shock are additional stresses that can lead to starvation (Nelson-Smith, 1973).

Behaviors of coastal birds affect their contact with oil. Some migratory waterfowl have been observed to settle on oil slicks preferentially because the surface is smooth (Nelson-Smith, 1973). Feeding behavior such as diving, tipping up, wading, or grazing will affect the degree of contact with oil that a species may experience. Wading birds, such as herons and egrets, may only contaminate their bills and heads which is unlikely to cause death but may produce sublethal effects (Breuel, 1981). Many waterfowl are colonial, and large numbers of birds may be susceptible to even small quantities of oil.

Nesting and resting habitats will also be affected by contact with oil. Loons and grebes, for example, often build floating nests which can easily be contacted by oil. (MMS, 1983a).

Very large numbers of birds, mostly marine birds, die annually as a result of oil pollution from sources other than OCS oil and gas operations. Chronic spills may kill as many as 100,000 birds a year (Nelson-Smith, 1973). Primary concern is not for the individual animal, rather for populations. A single spill event can have devastating effects on bird populations already at low levels and under stress. Some species have low reproductive rates, diminishing prospects for recovery if large numbers of animals are lost.

Oiled birds can be cleaned up, but the success rate varies between 1 and 50 percent (Nelson-Smith, 1973; Breuel, 1981). Even if birds survive, they must be released in time to join their colonies and be reaccepted into the colony's social structure if they are to breed. Sometimes, the cleaning can be as harmful as the oiling due to use of emulsifiers that destroy the natural water repellency of feathers (Clark, 1973).

Marine Turtles

Five species of marine turtles occur in OCS planning areas. Three species, the Kemp's Ridley, the Leatherback, and the Hawksbill, are endangered in all areas. One species, the Green, is listed as endangered in Florida and California but is considered threatened in other areas. The remaining species, the Loggerhead, is considered threatened in all areas. These marine turtles (except the Hawksbill) occur primarily in the warmer waters of the South Atlantic and Gulf of Mexico planning areas and are occasionally sighted in the waters of the southern California planning area. In addition, they occasionally occur in the more temperate waters of the North Atlantic and Pacific coasts during the summer (Fritts et al., 1983; MMS, 1983a).

The effects of oil on marine turtles are not well documented. Ingestion of spilled oil and tarballs has been involved in the deaths of a number of sea turtles (Witham, 1983). Most dead turtles have been recovered from the Atlantic Coast of Florida. Ingested tar was found in their stomachs. Based upon their analyses, Hall, Belisle, and Sileo (1983) proposed that the tar apparently sealed the mouths of the turtles and interfered with normal feeding. Mortality of marine turtles in the western Gulf of Mexico appears to be significantly higher than in the eastern waters, partially a result of incidental catch by shrimp trawlers (Fritts et al., 1983).

The life histories of marine turtles are poorly known. However, nearly all marine turtle sightings are on the nearshore continental shelf (Fritts et al., 1983; Winn, 1982).

Adult turtles returning to nesting beaches are guided by olfactory stimuli associated with the beach where they were born. In the nest, young turtles become imprinted with chemical cues which are detected through permeable eggshell. An oil spill which fouls a nesting beach might disturb the imprinting process in hatching turtles or confuse the return migration of adults to lay eggs. Geraci and St. Aubin (1983) proposed that the impact on

reproductive success could be significant. Field experiments in which paired subsamples of turtle eggs were incubated in clean and oil-contaminated sand did not document any significant effects on hatching success or hatchling development. Laboratory experiments utilizing sands treated with varied amounts of crude oil at the initiation of incubation demonstrated no effect on survival, but did cause detectable differences in hatchling morphology. Laboratory experiments in which the oil was added repeatedly during incubation caused significantly reduced survival of embryos and significant differences in hatching times and hatching morphology. Petroleum which has been aged and weathered prior to contacting turtle embryos is less toxic than fresh petroleum. The aged oil found on beaches during actual field experiments produced no detectable effects (Fritts and McGehee, 1982; Lutcavage, Lutz, and Odell, 1984). It is likely that oil spills washed up on nesting beaches will be significantly weathered.

Other possible consequences of spilled oil fouling of turtles in the open ocean include irritation and damage to sensitive periocular tissues and other exposed mucous membranes (Geraci and St. Aubin, 1983). Oil coating the head and eyes could also affect the orbital salt glands which are important in osmoregulation and other physiological processes (MMS, 1983b). High concentrations of hydrocarbons have been found in tissues taken from turtles after exposure to oil. This may reflect an inability to metabolize and eliminate these toxic materials, or perhaps result from their relatively slow metabolic rate (Hall, Belisle, and Sileo, 1983).

Since many turtle species feed on hard-bottom organisms, they may be attracted to the reef-like communities which develop on oil rig support structures. As a result, they may be exposed directly to operational discharges.

The most frequently used oil spill cleanup techniques include the use of mechanical collection and burning. With the exception of burning, and assuming the use of low toxicity dispersants when dispersants are used, the effects of cleanup operations on turtles are probably no worse than those from an oil spill.

In conclusion, the probability of juvenile and adult turtles encountering spilled oil from OCS operations in the open ocean is low. This is due primarily to the low frequency of oil spills resulting from OCS operations as well as the relatively small number and wide distribution of sea turtles. They are, however, threatened or endangered species and are accorded special protection status by legislative mandate. The low numbers of animals also make contact with oil, however improbable, a threat to the species. The impact of oil spills would also become significant during the spring and summer congregation of marine turtles to mate and eventually lay eggs at nesting beaches. As noted previously, the probability of oil being weathered prior to contacting nesting beaches is high. This would greatly reduce the toxic effects on developing eggs and hatchlings.

Marine Mammals

Although whales and other cetaceans are marine mammals, the effects of oil on them are discussed separately. Below, we consider only the potential effects

of oil on pinnipeds (seals, sea lions, and walruses), sea otters, polar bears, and the only sirenian (sea cow) that occurs in or near U.S. OCS waters (mainly off Florida). As described in the "whales" section, endangered marine mammals have commanded extensive attention and research on the likely effects to them resulting from oil spills and other OCS activity-related impacts. It is, therefore, relevant to note that the California population of sea otters (Enhydra lutris) is listed as threatened, whereas the northern or Alaska population is not, and that the sirenian, the West Indian manatee (Trichechus manatus), is listed as endangered. Furthermore, the Guadalupe fur seal (Arctocephalus townsendi) and the North Pacific fur seal (Callorhinus ursinus) are currently being considered for listing, while the Hawaiian monk seal (Monachus schauinslandi) is already listed as endangered. The last named is not considered in the following discussions because of the lack of potential OCS activity-related spills where they occur.

Direct contact with spilled oil may cause mortality of some marine mammals and have no apparent long-term effect on others, depending on factors such as species involved, age, and physiological status of the animal. Sea otters, fur seals, and newly born seal pups are likely to suffer direct mortality from oiling through loss of fur/water repellency and subsequent loss of thermoinsulation resulting in hypothermia. Sea otters are probably more sensitive to oiling because they rely entirely on their fur for thermoinsulation, while fur seals and other pinniped pups possess some subdermal fat layers--depending on age and physiological status. Adult harbor, ribbon, and spotted seals and walrus are likely to suffer some temporary adverse effects such as eye and skin irritation, with possible infection. Such effects may increase physiological stress and perhaps contribute to the death of some individuals (Geraci and Smith, 1976; Geraci and St. Aubin, 1980). Deaths attributable to oiling are more likely to occur during periods of natural stress--during molting, and times of fasting, food scarcity, and disease infestations. The few recorded mammals deaths attributed to oil spills in case histories occurred during winter months (Duval, Martin, and Fing, 1981), a season of increased natural stress.

Oil spill contact with marine mammals could interfere with olfactory sense. Hydrocarbons in the water column or in sediments could affect possible chemoreception in marine mammals. Oiling of pinniped fur may mask olfactory recognition of young pups by nursing females. The sense of smell has been reported to be important in harbor seal mother/pup bonds (Renouf, Lawson, and Gaborko, 1983) and probably is important in other seals. Benthic feeders such as walrus may rely on chemoreception for locating food. Contamination of bottom sediments may interfere with prey identification in contaminated habitats.

Oil ingestion by marine mammals through grooming, nursing, or consumption of contaminated prey could have pathological effects, depending on the species and physiological state of the animal. Although literature indicates that ringed seals, and probably other pinnipeds, rapidly absorb oil in body fluids and tissues (Geraci and St. Aubin, 1980), ingestion of relatively large quantities of oil for a short period of time showed no apparent acute organ damage (Geraci and Smith, 1976). However, with longer periods of ingestion, accumulation could increase. Oil ingestion may have serious acute effects on

polar bears. Engelhardt (1981) reported the deaths of two polar bears due to renal failure and red blood cell production dysfunction after the bears were heavily coated with crude oil and subsequently ingested large amounts of oil while grooming.

Review of oil spill case histories (Duval, Martin, and Fing, 1981) indicates that pinnipeds were contaminated following several oil spills. These accounts strongly suggest that marine mammals are not likely to avoid oil spills in all situations. Thus, if an oil spill contacts high-density pinniped habitat areas or seal and sea lion rookeries and major haulout areas during the pupping and breeding season, a few to several thousand individuals could be contaminated and suffer the above effects. Contact with oil may also cause marine mammals to at least avoid or abandon specific habitat areas, such as haulout sites and rookeries, which become contaminated.

Indirect consequences of oil pollution on marine mammals could be associated with changes in availability or suitability of various food sources. Toxic pollutant levels from oil spills and other industrial discharges that are concentrated enough to cause large-scale dieoffs of prey could occur near the immediate spill site or in other localized areas where pollutants have accumulated. Toxic pollutant levels from oil may become trapped in sediments and have long-term sublethal effects on prey organisms. These pollutants are also more likely to affect localized areas than extensive habitat areas. Sea otters, which live year round within limited home ranges or territories and feed generally on sedentary benthic prey, are probably the species most sensitive to local adverse changes in availability of food sources. If an oil spill contaminated bottom sediments, walrus--which also feed primarily on sedentary benthic organisms--may be affected by possible reduction or contamination of clams or other prey organisms within the wintering habitat areas in Alaska. Oil pollution effects on the pelagic prey of seals, sea lions, and fur seals are likely to temporarily reduce the numbers or availability of these food sources within localized areas near the immediate spill site and in areas where the oil slick is found. Because seals and sea lions are generally very versatile in diet and exhibit highly mobile foraging habits, indirect effects of oil on prey species are likely to have minimal effect on these marine mammal species populations.

According to F. R. Engelhardt (1981, personal communication), no reports exist on the effects of oil on sirenians, even though manatees, in Florida at least, are probably regularly exposed to hydrocarbon emissions from boating operations. The particular herbivorous habit of the sirenians leads to a complete lack of understanding of the influence of petroleum on their diet, bioaccumulation factors, effects on digestion, and physiotoxicological responses.

As was the case also for habitat recovery and damage to whales due to oil spill cleanup, these subjects have not been studied relative to other marine mammals. However, the Minerals Management Service contracted in Fiscal Year 1984 for the first part of a two-part study that should ultimately address, at least in part, the potential damage to California sea otters due to oil cleanup. Such studies assume greater importance for this population and other

marine mammals with comparatively small ranges in potentially oil spill-prone areas.

Whales

The protection and conservation provisions of the Marine Mammal Protection Act (16 U.S.C. 1361-1407) apply to all marine mammals, including all cetaceans (whales, dolphins, and porpoises). The often more restrictive provisions of the Endangered Species Act (ESA) (16 U.S.C. 1531-1543) apply, among cetaceans and within waters under U.S. jurisdiction, only to eight species of "great whales." These endangered whales include the bowhead (Balaena mysticetus), right (Eubalaena glacialis), humpback (Megaptera novaeangliae), gray (Eschrichtius robustus), blue (Balaenoptera musculus), fin (B. physalus), sei (B. borealis), and sperm (Physeter catadon). Only the last named whale has teeth; the others all have baleen for feeding. To varying degrees, these species occur, at least seasonally, in most OCS Regions except the Gulf of Mexico, which has generally sparse whale representation. The bowhead occurs only in the Alaska Region; the gray, in the Alaska and Pacific Regions. A small porpoise, the cochito (Phocoena sinus), is being considered for listing as endangered, but it is unlikely to be subjected to oil spills in U.S. OCS waters because it occurs only in the Gulf of California.

Effects of oil on whales have been studied meagerly and often indirectly, and the studies have focused mainly on endangered baleen whales because of their perceived greater sensitivity or "visibility" under the ESA, particularly its section 7 on Interagency Cooperation. Section 7 requires that a Federal Agency insure that any action it authorizes, funds, or conducts is not likely to jeopardize the continued existence of listed species or results in the destruction or adverse modification of their critical habitat. The Minerals Management Service (MMS) Environmental Studies Program contracted most of the studies noted below to answer questions raised during the section 7 consultation process. The study results may also apply, with reservations, to many nonendangered cetaceans, such as minke (baleen) whales (Balaenoptera acutorostrata), Bryde's (baleen) whales (B. edeni), beluga (Delphinapterus leucas), and other smaller toothed whales, dolphins, and porpoises. The effects of oil on listed noncetacean endangered and threatened species are discussed in the "Marine Mammals" section.

Oil may directly affect whales themselves or indirectly affect them through their food resources. No studies have documented such indirect effects as contamination of the whales' food supply owing to the lack of opportunities to investigate them.

Whales occupy surface waters to breathe, and some to feed, potentially exposing them to spilled oil and contact, inhalation, or ingestion (Geraci and St. Aubin, 1982). Geraci and St. Aubin (1982) performed oil detection experiments on dolphins in a controlled environment and on free-ranging gray whales. It was determined that during daylight and under optimum conditions of light and water clarity, dolphins could detect a thick film of dark crude oil within certain characteristics. The controlled experiment, although not directly related to baleen whales since echolocation has not been demonstrated in these species, also suggests that a dolphin using echolocation alone can

detect a patch of heavy oil, particularly if the heavy oil contains air bubbles as a result of churning by wind and waves. At sea, the response of dolphins and whales might be modified by social interactions, feeding, agonistic behavior, migration, or human activity. Geraci and St. Aubin (1982) also reported on the reaction of migrating gray whales to naturally occurring oil seeps. Swimming speeds, surfacing and diving times, and respiratory rates were compared relative to the presence and extent of oil. Typically, the whales were observed swimming through the oil at a modified speed, but without a consistent pattern, although some changes in respiration behavior were observed. In oiled waters, the whales seemed to spend less time at the surface, blowing less frequently but at a faster rate. If this reaction is interpreted as an avoidance response, it suggests that gray whales can detect oil. Whales showing no response either could not detect the amount or type of oil present or were indifferent to it. No comparable studies have been conducted on other baleen whales.

Laboratory studies with dolphin skin have revealed the skin exposure to gasoline and crude oil showed no gross evidence of damage or loss of integrity (Geraci and St. Aubin, 1982). Although skin turned a pale gray in color, it returned to normal color within 2 hours. Other surface contact studies by the same authors involved the progress of healing of oil-contaminated as opposed to uncontaminated cetacean wounds, and studies of skin to determine functional changes were reversible even after an exposure of 75 minutes. Albert (1981) speculated that crude oil may adhere to roughened areas of bowhead skin. By analogy, this could also be true for right whales, but no evidence exists to document harmful effects.

Field observations of at least one instance of possible contact of gray whales with spilled oil did not show evidence of extreme effects. In 1969, the entire northward migration of gray whales passed through or near the area contaminated by the Santa Barbara Channel spill. However, the number of gray whale strandings was not significantly different from previous years (Brownell, 1971).

The typical breathing cycle of cetaceans involves an "explosive" exhalation followed by an immediate inhalation of water and should be discriminatory of gas condensates and oil; however, toxic hydrocarbon gas could be inhaled (Geraci and St. Aubin, 1979). Geraci and St. Aubin (1982) calculated likely concentrations of toxic vapors over any oil spill. They concluded that toxic vapors are not likely to reach harmful levels and were not likely to affect whales adversely unless they are confined in the spill. No respiratory problems are expected from exposure to weathered oil. The effects of gas condensate or gas vapor inhalation on cetaceans are unknown. Albert (1981) suggested that tactile hairs around the blowhole of the bowhead whale function as sensory structures, and if spilled oil did adhere to these tactile hairs the sensory function could be compromised. Albert (1981) speculated that the blowhole tactile hairs may provide a sensory means for the whale to detect when the blowhole area is above the water surface.

Geraci and St. Aubin (1982) reported that ingested petroleum could be fatal if even small quantities are regurgitated and aspirated into the lungs. However, cetaceans are uniquely protected by an anatomical adaption of the larynx that

reduces or eliminates the possibility of aspirating regurgitated material. Food organisms can accumulate certain petroleum fractions, which are transferred in turn to cetaceans. However, the effects of such residues on marine mammals are not known. Cetaceans have enzymes which, when stimulated, are capable of detoxifying ingested oil. Albert (1981) speculated that oil ingested by a bowhead whale may hinder the digestive process, compromise the immune system resulting in decreased disease resistance, and cause a mechanical blockage in the form of large blobs of oil and baleen "hair balls" in the connecting channel between the two chambers of the stomach. Still, no studies have documented the physiological effects of ingested oil.

Fouling of baleen and subsequent decreases in feeding efficiency has been cited as another potential direct effect of spilled oil on baleen whales. The probability of such fouling and effects on feeding efficiency are directly linked to probabilities of spills and whale contact with such spills while feeding. Braithwaite, Aley, and Slater (1983) demonstrated average reduction of bowhead baleen filtering efficiencies of 5.9 to 11.5 percent if fouled with oil. How this reduction in filtering efficiency would affect an individual whale's overall health or energy acquisition is not known.

Baleen plates fouled with 10 millimeters of Prudhoe Bay crude oil showed a decrease in filtering efficiency for at least as long as 30 days when tested at 4 to 7°C. However, after approximately 8 hours, the filtration efficiency increased as the baleen hairs did not tend to stick to one another as much. Geraci and St. Aubin (1982) conducted fouling studies on fin and gray whale baleen plates and showed that although filtering efficiency of baleen was temporarily reduced by crude oil for up to 15 minutes, normal flow patterns were restored. These observations essentially alleviate the concern that crude oil would irreversibly obstruct water flow through baleen. However, it is unknown whether the persistence of oil on the fibers would contaminate food sources or cause them to adhere permanently. Prolonged impairment caused by repeated fouling might affect feeding activity.

Albert (1981) speculated that a bowhead whale would likely undergo ocular irritation as a result of contact with oil. The irritation would likely lead to reduced vision and eye mobility. However, no definitive data exist to substantiate this claim.

Habitat recovery and damage due to cleanup relative to oil on whales have not been studied. However, the former is not considered to be significant because a spill would occupy such a small part of most whales' habitat that any effect would be too localized and short-lived to have any long-term or measurable impact on them. Potential damage due to cleanup is considered equally unlikely because few whales would remain in the affected area during cleanup. An exception exists, however, if a significant part of a migrating population were to have to pass through a confined geographic area undergoing cleanup. Such effects are not currently known, under study, or under evaluation except in sale specific impact analyses of areas where such migration may occur (MMS, 1984).

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*Study sponsored by the OCS Environmental Studies Program.

Sensitivity to Other Impact-Producing Factors

The preceding papers focused on the potential impacts to various habitats and biota that could be caused by spilled oil. Other potential impact-producing factors were also considered. These are:

1. Drilling discharges (muds, cuttings, and produced waters).
2. Noise generated by OCS activities.
3. Habitat alteration from the installation of OCS facilities.
4. Air emissions from OCS operations.

The following discussions summarize existing information on the effects of these factors. These potential effects are singularly more limited in extent than the potential effects of a large oil spill. However, the cumulative effects of these factors may be more extensive and long lasting than the effects of a large oil spill. The Department of the Interior and other Federal, State, or local agencies have means available to mitigate many of the adverse effects of these factors. As a result, spilled oil remains the factor of greatest concern in this analysis.

Drilling Discharges

Muds and Cuttings

Drilling muds and cuttings may be discharged nearly continuously in small quantities while drilling is underway during exploration. Larger discharges may occur several times during the 2 to 6 months usually required to drill a well and a few times at the end of drilling. The total amount of dry solids discharged over the life of an exploratory well is approximately 2,000 tons or 1,000 cubic meters of material. The quantity of drilling muds discharged during development drilling may be as much as 25 percent less than exploration discharges because development wells are normally shallower and smaller in diameter, and some of the mud is recycled for additional well drilling. These muds are typically a mixture primarily of barite and clay, with small amounts of lignosulfonate, lignite, sodium hydroxide and various additives, including diesel fuel which is used as a lubricity agent.

The physical fates of discharged drilling muds and cuttings vary widely as a function of the water depth, ice cover, waves, currents, and general hydrodynamic features of the OCS area. On the OCS, horizontal turbulent diffusion results in dilution of discharge plumes by a factor of 10,000 or more within an hour of release. The concentration of suspended components is reduced significantly from settling (National Research Council (NRC), 1983; Dames and Moore, 1978). While dilution may be inhomogeneous at thermoclines or pycnoclines, the high dilutions predicted in mathematical models have been confirmed by field studies. Theoretical considerations and empirical observations yield the same values for dispersion rates in the water column (NRC, 1983). This results in plume concentrations of suspended particulates which approach background levels (less than 10 mg/l) anywhere from a few hundred to a few thousand meters from the discharge. In the benthic environment, the resuspension and transport of deposited drilling discharge components also reduce the concentrations of the drilling muds.

More than 96 percent of more than 20 whole drilling fluids tested in short-term experiments (from 44 to 144 hours) had LC50 values greater than 1,000 ppm (1 ppm is roughly equivalent to 1 mg/l) and are classified as "slightly toxic" or "practically non-toxic" by the Intergovernmental Maritime Consultative Organization et al. (1969). The National Research Council (1983) reported that the results of toxicity tests also indicate that organisms from all Regions have about the same sensitivity to drilling fluids. More than 60 species from 5 phyla have been used in the studies reviewed by the National Research Council. Recent studies (Conklin et al., 1983; Duke et al., 1984) indicate that the presence of diesel-like hydrocarbons in drilling muds may contribute significantly to the toxicity of the mud.

The concentrations of mud necessary to produce the type of effects observed in laboratory experiments (burial, avoidance) are encountered only very near the discharge. The concentrations necessary to produce effects on adults occur only within a few meters of the discharge. The concentrations necessary to produce effects on larvae occur only within several hundred meters of the discharge. Because of the rapid dilution of the discharge plume, a toxic

response in organisms would be anticipated only if short-term exposures would produce acute effects with concentrations of drilling muds less than 100 ppm. Very few experiments, and those usually long-term (96 hours), have identified lethal or sublethal effects at these concentrations (National Research Council, 1983). Houghton et al. (1981), concluded that likelihood of significant impacts on plankton and nekton in dynamic areas such as Cook Inlet and Georges Bank was low because of the low toxicity of discharged drilling muds and the relatively high dispersion rates. The National Research Council (1983) concluded that because the effects of drilling fluids are largely physical, recovery times should be similar to those following other physical seabed disturbances. These times vary widely; recovery may take weeks in frequently disturbed shallow communities to years in continental shelf and slope communities. The NRC (1983) concluded that long-lived communities which are characteristic of hard substrate epibiota, may be particularly susceptible to long-term effects if they are exposed to large concentrations of deposited muds and cuttings, but many of these communities are not very likely to accumulate such materials unless the materials are deposited directly on them. In the study of impacts of drilling muds on benthic infaunal communities in the Georges Bank area, Battelle (1984) concluded that no significant changes in benthic community structure could be detected which could be attributed to the drilling of eight wells.

There have been a number of laboratory investigations that show that some heavy metals in drilling fluids are bioavailable to marine organisms (Brannon and Rao, 1979; Carr et al., 1982; Gerber et al., 1981; Liss et al, 1980; and others). Liss et al. (1980), have found higher concentrations of chromium and barium in filtrates of seawater suspensions of drilling fluids than would be predicted; this may be the fraction bioaccumulated by marine organisms.

A study of an exploratory drilling discharge in the Baltimore Canyon off New Jersey found statistically significant elevated concentrations of barium and chromium in some samples of mixed-species assemblages of brittle stars, molluscs, and polychaetes collected approximately 2 weeks and 1 year after drilling had ceased (EG&G Environmental Consultants, 1982). No statistically significant increases in mercury levels in biota were found. Payne et al. (1982), could find no indication of any increase in the concentration of barium, chromium, or several other heavy metals in the tissues of bivalve molluscs Arctica islandica or of demersal fish near exploratory drilling on Georges Bank.

The National Research Council (1983) stated that field results tend to corroborate laboratory findings that accumulation of heavy metals from drilling muds by organisms is very low. The metals of concern are typically in the form of an insoluble inorganic sulfide or sulfate (MacDonald, 1982), although chromium is associated with lignosulfonate. Heavy metals in the form of insoluble sulfides, adsorbed to particulates, or in the form of nonlabile organic complexes, have a much lower bioavailability to marine animals than do metal ions in solution (Breteler et al., 1981; Bryan, 1982; Jenne and Luoma, 1977; Neff et al., 1978).

The National Research Council (1983) observed that high levels of metal in a sediment or drilling fluid sample are not by themselves an indication of a

biological hazard because these adsorbed metals have very limited biavailability. Moreover, the limited metal accumulation observed in laboratory and field investigations suggest that the biological effects of this accumulation are minimal.

While hazard assessments have been and will be developed based on extrapolation of results from sublethal tests, it should be noted that there are no well-established relationships between realistic exposure intervals and the responses elicited over longer periods. Extrapolation is necessary because the experiments conducted did not simulate the rapid dispersion of drilling fluids nor their movement along the bottom.

In conclusion, the National Research Council (1983) found that ". . . the environmental risks of exploratory drilling discharges to most OCS communities are small." However, ". . . uncertainties regarding effects still exist for low energy depositional environments, should they experience large inputs of drilling discharges over long periods of time." The impacts from development drilling are probably less than additive, and the results from exploratory rig monitoring are probably a reasonable indication that significant impacts are not likely to occur on the OCS.

After a review of the comprehensive literature describing the fates and effects of drilling muds discharged into the marine environment, it was determined that the development of the oil and gas resources in the proposed 5-year leasing program will not have significant, large-scale negative impacts on OCS marine ecosystems in any of the planning areas. This determination is based on discussions contained within lease-sale-specific EIS's, recommendations, and conclusions from various technical and policy workshops, the deliberations of the NRC's Marine Board Panel on the Assessment of Fates and Effects of Drilling Fluids and Cuttings in the Marine Environment, and the Interagency Committee on Ocean Pollution Research, Development and Monitoring draft report on the Long-Term Effects of Oil and Gas Development. These discussions include the results from the monitoring of exploratory rig drilling mud discharges in the North Atlantic, Mid-Atlantic, Western Gulf of Mexico, Southern California, and the Alaskan OCS which have supported the general belief that open-ocean discharges will be rapidly dispersed and have minimal effects on biota (Battelle, 1984; Ecomar, 1978; Ecomar, 1983; Dames and Moore, 1978).

Produced Waters

"Formation" or "produced" waters are those waters and particulate matter associated with oil and gas producing formations. The amount of produced water generated is primarily dependent on the method of oil production, field characteristics, and location. Water may also leak into the oil formation from shallower strata through leaky casings or faulty completion. This water may also find its way back to the surface as produced water. As oil and gas production decline, most wells produce increasing amounts of free water, with other fields producing as much as 95 percent water and 5 percent oil and gas. In 1970, daily production (onshore and offshore) of produced water in the United States was 1 trillion gallons with about 399.4 billion gallons of oil (Collins, 1975). In the northwestern Gulf of Mexico, an estimated

12.6 million gallons of produced water per day were discharged to OCS waters (Gianessi and Arnold, 1982). An additional 12.4 million gallons per day were treated onshore and discharged to coastal waters (Brooks, Bernard, and Sackett, 1977). The produced water discharged from a single platform usually is less than about 400,000 gallons per day, whereas discharges from large facilities handling several platforms may be as high as 6.6 million gallons per day (Menzie, 1982). The oil/water mixture produced from the well is either treated on the platform or transported to shore by pipeline to an onshore treatment plant. Typically, the oil and water phases are allowed to separate in a gravity separator, and the water is further treated to remove additional dispersed oil so that it satisfies EPA guidelines before being discharged. Treatment is designed to remove particulates and dispersed oil but has little effect on dissolved hydrocarbons and metal ions (Jackson et al., 1981; Lysyj et al., 1981; Lysyj, 1982).

Produced waters may be high in total dissolved solids (salinity), oxygen demanding wastes, and toxic metals, in addition to oil and grease contaminants (U.S. EPA, 1975). Aromatic hydrocarbons have been measured at the part per million level in various programs in the Gulf of Mexico (Middleditch, 1984). The following metals have been reported at significantly enhanced levels in produced waters: antimony, arsenic, barium, beryllium, cadmium, chromium, copper, iron, lead, manganese, mercury, nickel, silver, strontium, thallium, and zinc (Collins, 1975; Middleditch, 1983). Additionally, high concentrations of naturally occurring radionuclides are found in formation waters (Ried, 1983).

Dilution of formation waters discharged occurs rapidly, with the rate a function of the salinity, current speed, vertical convective mixing of the water column and the water depth. Several field studies (Armstrong et al., 1979; Lysyj et al., 1981; Neff, Marum, and Warner, 1983) have reported dilutions in total hydrocarbons ranging from 500 to 3,000-fold within 1,000 meters of the produced water discharge. Anikouchine (1984) predicted that even with the high dilution, deposition of metal-rich particulates originating in, or from contact with, discharged formation water would increase metal concentrations in sediments above ambient levels in the Point Arguello, California, areas.

Nine species of marine/estuarine organisms have been used in acute lethal bioassays using produced waters. Eighty-six percent of the LC50 values were above 10,000 ppm produced water in seawater (Rose and Ward, 1981; Andreasen and Spears, 1983; Zein-Eldin and Keney, 1979). The most toxic sample had an LC50 of 1,750 ppm which was attributed to the presence of biocides (Zein-Eldin and Keney, 1979). The toxicity of brines from Texas and Louisiana salt domes was evaluated (NOAA, 1978) and found to be not significantly more toxic than an artificial hypersaline solution prepared with artificial sea salts, suggesting that formation water brines have no particular additives which contribute to their toxicity. Produced waters also have varying amounts of phenols, amino acids, fatty acids, other organic acids, alcohols, and naphthenic and humic substances (Collins, 1975; Lysyj, 1982). The toxicity of these substances to marine organisms is not known. Laboratory bioassays (Zein-Eldin and Keney, 1979; Rose and Ward, 1981) and field studies with caged

fish (Workman and Jones, 1979) indicate that produced water is significantly more toxic when biocides are being used.

The most sensitive organism evaluated by Rose and Ward (1981) was larval brown shrimp. The LC50 ranged from 160,000 ppm at 3 hours to 8,000 ppm at 48 hours. Rose and Ward (1981) applied a conservative application factor of 0.01 to these values and compared the resulting limiting permissible concentrations of produced water (the estimated highest concentration causing no adverse biological impacts) to the estimated concentrations of produced water in the ocean at different times after discharge, based on a conservative use of the dispersion model developed for vertically distributed pollutants in the Buccaneer Field (Smedes, Herbst, and Calman, 1981). The limiting permissible concentration or produced water was approximately four orders of magnitude greater than the estimated environmental concentration of formation water at all times. The authors concluded that discharge of formation water does not represent a potential hazard to water column organisms drifting or swimming through the wastewater plume.

Bascom (1983) suggested that inorganic metals in the sea are not a hazard to marine animals because they quickly precipitate or adsorb to particulate matter and settle to the bottom in a form that is not readily available or toxic to marine organisms. Little information is available about the chemical forms of metals in produced waters and the chemical transformations that take place when produced water is discharged to the oceans. The MMS (1983) concluded that radionuclides would not present a hazard to human health or the environment because of the rapid dilution of formation waters when discharged on the OCS.

Middleditch (1984) combined predictive and observational strategies to describe the ecological effects of produced water effluents and concluded that current practices for the disposal of produced waters are ecologically sound.

In summary, produced waters are not expected to produce a significant impact in open waters because of the rapid dilution that occurs. In shallow coastal waters where residence times may be higher and flushing rates lower, such discharges may impact benthic organisms. In those cases, only local impacts are to be expected.

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Noise

Airborne and waterborne noises generated by OCS activities, unless controlled of their effects mitigated, may severely adversely affect the behavior and vital activities of endangered/threatened and nonendangered/nonthreatened whales, other marine mammals, and marine, coastal, and migratory birds. Major sources of mobile OCS airborne noise disturbance include low-flying aircraft, high-speed motorboats, and on-ice vehicular traffic associated with ice roads and over-ice seismic operations in the Arctic, as well as other high-frequency, high-pitched sounds. Major stationary sources of airborne noise include artificial island construction, dredging, and drilling. Major sources of waterborne OCS noise include open-water seismic operations, aircraft, drill rigs, dredges, support vessels, pipeline construction, and production and processing facilities. In some cases, these noises may potentially jeopardize the continued existence of some of the animals and birds mentioned earlier by interfering with or disrupting such critical activities as feeding, mating, birthing, nesting, migrating, and resting.

In all cases, the MMS can and does control or otherwise influence the sources of these noises through operating orders and regulations, sale-specific stipulations and Information to Lessees clauses, regional or areawide Notices to Lessees and Operators, and conditions accompanying MMS-isssued permits or approvals to conduct specific activities. Because of these controls and mitigative measures, noise is not considered to have significant large-scale negative impacts on these animals and birds.

The remainder of this section details examples of noise and their effects of the parts of marine biota mentioned earlier. Ljungblad et al. (1980, 1981, 1982, and 1983) have been conducting aerial surveys of the Alaskan Beaufort Sea to determine the distribution and abundance of bowhead whales. Part of this effort (Reeves, Ljungblad, and Clarke, 1983) has been to monitor the effect of operating seismic boats on the behavior of the bowhead whale as it migrates westward in the Alaskan Beaufort Sea. In 1981, 3 incidents of seismic sounds were recorded in the presence of a total of 126 whales ranging from 9 to 157 km from operating seismic boats. There was no flight reaction by bowhead whales to seismic sounds.

Gales (1982) studied effects of sound on marine mammals including whales. The available scientific literature was surveyed for data on noise from oil platforms and on hearing capabilities of marine mammals. Data on animal behavior around the platforms was collected by field observations and interviews. The noise from platforms was measured at various geographical locations and analyzed. Evaluation of the combined data indicates that certain platforms are relatively quiet; thus, platforms with minimal sound emission can be designed. The highest level components of the noise from oil platforms are below a frequency of 100 Hz. The distances at which large whales can detect such noise were estimated for various geographical locations. It is unlikely that platform noise will interfere with echolocation of marine mammals, and according to anecdotal information, whales ignore or easily avoid the platforms.

Fraker et al. (1980, 1981), and Richardson et al. (1983, 1984), have studied the effect of noise associated with OCS activities on the behavior of the bowhead whale. These activities included boat and aircraft traffic, seismic exploration, drilling, and dredging. The study area was the Canadian Beaufort Sea which is the summering area for the bowhead whale. The results showed that the behavior of bowhead whales can be affected markedly by the close approach of boats (2 to 3 km) and aircraft (610 m). However, the whales seem to return to their normal activities soon after the boat or plane moved away. The results showed quite clearly and consistently that summering bowheads normally do not swim away from seismic vessels operating 6 or more km away. There was no consistent identification of unusual behavior among bowhead whales observed within 20 km of drillships. Bowhead whales have been frequently within 5 km of dredging operations.

Malme et al. (1983), studied the potential effect of noise associated with OCS activities on the behavior of migrating gray whales. The experimental design included the playback of prerecorded sounds and the actual operation of full-scale seismic exploration air gun systems. The playback experiments included the following prerecorded sounds: drillship, semisubmersible drill rig, drilling platform, production platform, and helicopter. Experiments were conducted with a seismic boat operating an air gun array and a research vessel operating a single air gun. The field measurement area was located south of Monterey, California, at Soberanes Point. The results of the first year of study indicated that gray whales responded to playback recordings at less than 200 m from the source, with the exception of drillship sounds which elicited a response at less than 2.7 km. Gray whales responded to the air gun array at less than 5 km from the source, while behavioral responses from the single air gun were observed at less than 1 km from the source.

Stewart, Awbrey, and Evans (1983), conducted playback experiments with beluga whales in the Snake River, Alaska, using sounds recorded near an operating oil drilling rig. Beluga whale responses to playbacks of oil drilling sounds indicated that direction of whale movement and general activity (feeding, travelling) were not greatly affected by these sounds, especially if the sound source was constant. Whales continued to move in the direction they were travelling before playback began. On several occasions, whales within 2 km of the sound source appeared to feed during playback experiments.

Experiments exposing captive beluga whales to the same sounds (Thomas and Kastelein, 1983) indicated that beluga whales can acclimate quickly to oil-drilling sounds at typical sound levels. This agrees with McCarty's (1981) observations. He reported that beluga whales (including mother-calf pairs) regularly approached to within 10 m of oil production platforms in Cook Inlet. He also reported that as long as noise from these platforms was constant it did not seem to affect beluga whales, but that a sudden change in noise levels elicited a temporary avoidance reaction. Observations also indicate that beluga whales usually respond to sudden acoustic disturbance but are less likely to avoid a constant sound source.

Noise from over-ice seismic operations may displace ringed seals from important denning and pupping habitats. A comparison of ringed seal densities between areas of seismic exploration and areas where no over-ice seismic

activities occurred (using aerial data collected in June 1975 to 1977 to investigate variation in ringed seal distribution) showed a lower density of seals in areas where there had been seismic exploratory activity (Burns, Shapiro, and Fay, 1980). However, such survey data are only an indication of overall survival through the long winter-spring period and provide no insight into the nature, extent, or causes of changes recorded (Burns and Kelly, 1982). Results of surveys conducted in 1981 were ambiguous regarding whether seismic exploration results in displacement of ringed seals (Burns, Kelly, and Frost, 1981). Subsequently, Burns and Kelly (1982), conducted ground examination of ringed seal den structures to determine the fate of such structures along seismic lines and along control lines. The latter investigators reported no significant overall difference in fates of structures between seismic lines and along control lines. However, they reported significant differences in fates of structures in relation to distance from seismic lines (within 150 m of the shot line in comparison to beyond this distance). The investigators concluded that displacement of seals in close proximity (within 150 m) to seismic lines does occur. However, based on data from aerial surveys in 1982, there is no large-scale displacement of seals away from over-ice seismic operations as currently conducted in the Beaufort Sea.

Noise from land-based industrial activities and over-ice seismic operations may also be significant near polar bear dens because female polar bears generally den on coastal terrestrial habitats or on land-fast ice while giving birth and nursing their young. Experience with captive female polar bears suggests that these bears can be especially sensitive to noise and human presence during maternity denning. However, preliminary results of noise measurements taken within a simulated polar bear den suggest that seismic activities would only be detected by denning bears if such activities occurred very near the dens (Burns, personal communication, 1983).

The presence of sea lion, elephant seal, and sea otter populations in close proximity to human development and intensive industrial activity and marine-vessel traffic along the California coast strongly suggests that some marine mammals have adjusted to human development activity with no apparent adverse effects. Playback recordings of industrial noise, and actual seismic sounds from air guns had no apparent effect on California sea otters (Riedman, 1983). However, some species of marine mammals are probably more sensitive to human presence and disturbance, particularly during nursing and breeding seasons. Sensitive species may adjust to human presence and industrial noise to a certain degree, with a portion of the population remaining in disturbed areas. However, noise and disturbance may exceed the tolerance level of sensitive species, eventually displacing this species completely from development areas.

Species such as fur seals, Steller sea lions, and harbor seals that congregate in large social groups for breeding and pupping may be the most sensitive marine mammals to cumulative noise and disturbance. Low-flying aircraft are known to panic hauled out seals. If such disturbance occurs at marine mammal rookeries during the pupping season, a significant increase in pup mortality and reduced pupping success are likely to occur (Johnson, 1977). Disturbed adult seals are likely to crush pups when they stampede into the water, and nursing females are likely to abandon their pups during the first 3 weeks of

nursing if disturbance separates the mothers and pups. If seals and sea lions are frequently disturbed during the molting period at haulout areas, the successful regrowth of skin and hair cells may be retarded, thus increasing physiological stress on seals and sea lions during a normally stressful period. Increasing noise and human activity near rookeries, such as on the Pribilof Islands, could exceed the disturbance tolerance level of fur seals and result in the complete or partial abandonment of some rookery or haulout sites on the islands.

Endangered peregrine falcons are likely to be adversely affected by uncontrolled airborne noise and disturbance, especially that associated with supply aircraft serving offshore facilities and potentially passing close to nesting sites. Disturbance from such sources could reduce the survival of nestlings. Noise and human activities attendant with the construction of onshore facilities near peregrine nesting sites could also be a potential source of disturbance.

Marine birds may be severely disturbed by helicopter and vessel traffic to drilling rigs. Onshore air traffic associated with operation of support facilities near seabird colonies and waterfowl and shorebird staging and nesting areas can significantly disrupt breeding activities and preparation for migration. Low-flying aircraft, especially helicopters, can frighten large numbers of cliff-nesting birds (e.g., murres) from the nesting ledges, resulting in displacement of eggs and/or young to the rocks below. Those not displaced from the ledges by adults are left exposed to the elements and predators (Hunt, 1978; Jones and Petersen, 1979). In recent years, repeated aircraft flights near several colonies in the Bering Sea may have been one factor contributing to fewer nesting attempts and reduced reproductive success (Hunt, 1978; Biderman and Drury, 1978). Disturbance of birds in important feeding, staging, and overwintering areas can cause excessive expenditure of energy and displacement to less favorable habitats during critical periods in the annual cycle.

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Habitat Alteration

The placement of facilities needed for oil and gas operations may result in physical alteration of habitats. The legs of a jackup rig or a fixed production platform and the anchors of a floating platform will disturb bottom sediments and benthic communities. The severity and duration of impacts depend on the local bottom conditions and habitats. Platform installation and anchor placement could damage live hard bottoms or coral reefs or destroy certain fishery habitats, such as tilefish burrows. Rig and platform installation could disturb both surface and buried archaeological sites. However, geophysical surveys required before siting a drilling rig or platform help identify sensitive areas that could suffer adverse or long-term damage so that they can be avoided. In soft-bottom areas, no significant physical damage is likely to result from platform emplacement.

A platform provides substrates for the attachment of biota which attract fish and other animals either to feed or find refuge. The concentration of fish around platforms may represent an increase in the population carrying capacity of those species or a concentration of existing population. Gallaway and Lewbel (1982) support the population enhancement hypothesis for the Gulf of Mexico where the presence of platforms is considered a boon to fishermen. While fisheries population enhancement may occur in other areas, platforms can also restrict certain fishing methods, such as trawling and drift net fishing, that are important in the Atlantic and off California.

Because of ice hazards in the Arctic, gravel islands and causeways are constructed as a base for drilling. These structures permanently bury or displace the benthic community. Offshore dredging for materials for these structures can also result in habitat alteration. However, Boesch et al. (1984), judged all of the long-term effects of constructing gravel islands and causeways in the Arctic to be of low severity.

Pipeline installation also causes considerable disruption to the bottom. Approximately 6 acres of the bottom is physically disturbed per mile of pipeline laid; some 2,300 to 6,000 cubic yards of sediment are resuspended per mile of pipeline, depending on the size of the pipeline and the depth of trenching or burial (MMS, 1983). Added to this is the damage caused by the anchors of the pipelaying barge. Considerable damage could be done if such activities are conducted in sensitive areas.

The siting of pipeline landfalls must account for the presence of sensitive environmental areas which could require long periods of time to recover. These include important habitats such as spawning and nursery areas or shellfish beds. Coastal areas that would be desirable for landfalls would have sandy or firm sediments and be gently sloping (less than 10 percent grade) (Gowen and Goetz, 1981). A pipeline crossing a barrier beach would predispose the landfall site to considerable erosion if the pipeline trench is not carefully backfilled and the area revegetated to reestablish any dunes. Beach erosion can be prevented by burying the pipeline to depths where wave action would not uncover the pipeline and cause scouring (MMS, 1983).

Infrastructure development, especially pipelines and onshore support facilities, can destroy or disrupt wetland habitats permanently. Pipeline emplacement in sensitive coastal habitats, such as wetlands, can result in impacts in the form of marsh loss and changes in salinity regimes. The effects of wetland alterations contribute to extensive and permanent loss of coastal habitats with the attendant loss of biological productivity (MMS, 1983). Boesch et al. (1984), proposed that this is a particular problem in Louisiana where the needs of the oil and gas industry have contributed to this phenomenon. Gonsoulin, Laird, and Wallis (1984) state that although "drilling access and pipeline canals have had the effect of promoting salt water intrusion when canal plugs are not maintained, it is now believed that the levee and flood control structures along the Mississippi and other river systems are the major culprit in the steady subsidence, cutting off the sediment base load and tipping the scales in favor of the erosive forces at work. It is a complex problem that has no simple solutions."

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Air Emissions

In developing the Clean Air Act, Congress determined that increased air pollution resulted in mounting dangers to the public health and welfare. To define the amount of pollution considered detrimental, Congress directed that the U.S. Environmental Protection Agency (EPA) set national primary and secondary ambient air quality standards (NAAQS) that were sufficient to protect the public health and welfare. The EPA developed NAAQS for carbon monoxide (CO), ozone (O_3), nitrogen dioxide (NO_2), sulfur dioxide (SO_2), total suspended particulates (TSP), lead, and non-methane hydrocarbons.

Air pollutants are emitted from OCS facilities in the form of nitrogen oxides (NO_x), SO_2, TSP, CO, and volatile organic compounds (VOC). Under certain conditions, NO_x and VOC emissions can contribute to the formation of ozone. Although nearly all OCS operations will result in some emissions of all of these pollutants, activities associated with power generation and transportation and processing of hydrocarbon resources are responsible for the majority of emissions. Power-generative equipment (such as gas turbines and diesel engines needed to run drilling and pumping operations) generally produces the largest amount of pollutants from OCS facilities, with NO_x normally the pollutant emitted in the largest amount. The amount of all pollutants produced depends on the operating characteristics of the engine, such as size, type, period of use, and type of fuel burned. Diesel engines produce the largest amount of emissions of pollutants; gas turbines emit lesser amounts. If oil production is transported to shore by barge or tanker, large amounts of VOC can be emitted by the displacement of hydrocarbon vapors during barge loadings. Vapors remaining in the hold from prior shipments are pushed out into the atmosphere as the hold fills with oil. However, the use of vapor balance lines in such transfer operations would largely reduce hydrocarbon vapor emissions. Normally, production is pumped to shore through pipelines, and such emissions are avoided. However, significant emissions of SO_2 from gas processing activities can be avoided by installing tail gas treatment or sulfur recovery units. Large amounts of SO_2 can be emitted from facilities producing sour natural gas (gas containing a relatively high concentration of hydrogen sulfide, H_2S) that is processed offshore. SO_2 emissions resulting from processing sweet gas (low H_2S content) are normally not a problem.

The DOI air quality rules (30 CFR 250.57) provide for the protection of onshore air quality by ensuring that it is not significantly affected by emissions from OCS facilities. The rules require installation of Best Available Control Technology and/or the acquisition of emission offsets if an OCS facility by itself or cumulatively with other OCS facilities in an air basin exceeds 1 to 3 percent of the applicable NAAQS levels that have been designated as significant by DOI. These levels were based on information provided to the Minerals Management Service (MMS) by EPA during the original rulemaking process and have been reaffirmed by EPA since the final promulgation of the rules in March 1980.

Recent EPA rulings (Kentucky vs. Indiana; Interstate Pollution Abatement: Final Determination (47 FR 6625); New York, Pennsylvania and Maine vs. Out of State sources in the Midwest: Interstate Pollution Abatement; Proposed Determination (49 FR 34851) September 4, 1984) and court decisions (Connecticut Fund for the Environment, Inc. vs. EPA, 696 F. 2d at 175, 177 (2d Cir. 1982); Air Pollution Control District vs. EPA, No. 82-3214 (6th Cir. 1984) July 10, 1984) upholding the EPA rulings have ruled that impacts by particular sources located outside the nonattainment area boundaries as high as 5 percent of the applicable NAAQS are not significant impacts.

Past EIS analyses of air quality impacts (Sales 73 and 80 EIS's, Santa Ynez and Point Arguello EIS/environmental impact reports in California, Lease Sale EIS's for Gulf of Mexico (94, 98, 102), and Atlantic (82)) indicate that OCS impacts are less than the DOI significance levels. If future lease sales are similar in scope and proposed level of development, the impacts from these sales will also be less than the DOI significance levels. However, cumulative impacts from OCS development may cause concentrations above the DOI significance levels. Mitigative measures as required by the DOI air quality regulations would prevent significant air quality impacts.

The recent Secretarial Decision Material for air quality for Lease Sale 80 included an analysis of the relative contribution of emissions from OCS facilities to air basin emissions in California. In all cases except emissions of NO_x, emissions from OCS facilities were less than 2 percent of total onshore emissions. For NO_x, OCS sources contributed approximately 7 percent of total air basin emissions; but the Sale 80 EIS still concluded that cumulative onshore NO_2 impacts from OCS activities were less than the DOI significance level (which is 1 percent of the NAAQS for NO_2).

Though greater OCS activity occurs in the Gulf of Mexico, the provisions of the DOI rules that impose mitigative measures for sources or groups of sources significantly impacting onshore air quality insure that human health and general welfare will not be adversely impacted by these sources. Impacts to regional visibility have been determined to be insignificant and aesthetic impacts from visible emissions would also be insignificant.

APPENDIX J

AVAILABILITY OF TRANSPORTATION NETWORKS TO BRING OIL AND GAS TO REGIONAL ENERGY MARKETS

AVAILABILITY OF TRANSPORTATION NETWORKS TO BRING OIL AND GAS TO REGIONAL ENERGY MARKETS

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III. Transporting Landed Resources to Refinery and Demand Centers J-4

AVAILABILITY OF TRANSPORTATION NETWORKS TO BRING OIL AND GAS TO REGIONAL ENERGY MARKETS

I. Introduction

Section 18(a)(2)(C) requires that the timing and location of Outer Continental Shelf (OCS) oil and gas operations be based upon a consideration of the location of oil and gas bearing physiographic regions with respect to, and the relative needs of, regional and national energy markets. To provide for such consideration, an analysis of the availability of transportation networks has been prepared.

A previous analysis was included as Appendix 4 of the 1982 Secretarial Issue Document (SID) prepared for the 5-year Oil and Gas Leasing Program. The analysis divided the transportation issue into two parts--bringing oil and gas resources to shore and transporting landed resources to refinery and demand centers. The transportation analysis presented below uses an identical methodology to review and analyze the availability of oil and gas transportation networks.

In analyzing the availability of transportation networks to deliver oil and gas to demand areas, both current and proposed networks were reviewed for all OCS planning areas. In addition, data submitted by State and local governments, Federal Agencies, industry, and the public in response to letters to the Governors of affected States and to the heads of relevant Federal Agencies, dated July 5, 1984, and a July 11, 1984, Federal Register Request for Comments notice were also used. The results of this analysis have confirmed that the decision of whether to use pipelines, barges, or tankers to transport OCS oil and gas to shore is dependent on a number of factors, including technological constraints, environmental preferences, and economic considerations. The exact mode of transport cannot be determined until the amount of recoverable reserves is known and judgments are made as to what is environmentally preferable and technically and economically feasible.

Further, it is understood that in order for a hydrocarbon find to be economically feasible, an accessible transportation system must be in existence or a new one must be created. Transportation systems are not built in anticipation of hydrocarbon discoveries. This is especially true in frontier areas where knowledge of hydrocarbon resources is spotty or nonexistent and anticipated transportation costs are generally very high due to the lack of existing infrastructure.

Based on previous analysis and completed projects, pipelines are generally preferred by the oil companies for transporting oil and gas to processing facilities when economics and other considerations justify their construction. Where pipelines cannot be justified, tankers or barges are necessary. In California, although pipelines have almost always been used over tankers, in some instances tankers are preferred by the oil industry. Tankers, in some cases, allow greater flexibility in terms of getting oil to refineries and market centers. Not all of the oil companies have local refineries or local refineries with the capability of handling high sulfur or heavy crude like that being found off California.

The present analysis is limited to examination of issues related to transport of product among domestic market areas. There has been extensive public debate for and against sale and transport of Alaskan crude oil to Japan. Such sales currently are prohibited by Federal law. If authorized, OCS oil and gas resources could be delivered more cheaply to Japan than to many domestic market areas.

II. Transporting Oil and Gas Resources to Shore

At present, pipelines are generally used to bring oil and gas ashore in both the Gulf of Mexico and Southern California planning areas. The Gulf of Mexico is the only area with an extensive pipeline system, including a network of oil and gas gathering systems and trunk lines. In Southern California, the only other commercially producing OCS area, pipelines are desirable because, once installed, they generally do not adversely affect air quality commonly associated with tanker terminal use. The State of California also prefers pipelines due to their belief that there is a lower risk of oil spills. However, tankers are employed in Southern California in a variety of situations to transport oil to refineries.

Expansion of the offshore oil and gas pipeline systems in Southern California and the Gulf of Mexico is continuing as needed to extend pipelines into new production areas. For example, a number of discoveries have been announced in the Santa Maria Basin on the California OCS. As as result, several large production projects are expected to be coming on line in the near future and are likely to transport oil and gas ashore by new pipelines to a consolidated onshore processing facility. Also, OCS development support facilities within California are being consolidated to minimize the number of pipeline landfalls. Similarly, any new production in the Central and Western Gulf of Mexico is also expected to use pipelines. In many cases, only new gathering lines are likely to be required in the Gulf of Mexico region to connect with existing trunk systems.

In areas where there is currently no production, such as the Atlantic OCS, an alternative transportation system may be required. Because of both the size and location of potential Atlantic OCS fields, it is expected that all Atlantic OCS crude would be transported to shore by tankers. The same is likely to be true for any oil found where the resources may not economically justify pipelines, for example in Central and Northern California and in the Eastern Gulf of Mexico.

As there is not yet any oil and gas production on the Alaska OCS, transportation systems there are still speculative. However, three basic networks have been identified based on geography. The first involves oil and gas transportation from the Beaufort Sea, Chukchi Sea, and hope Basin planning areas. Produced crude oil is expected to be transported through subsea and overland pipelines to the Trans-Alaskan Pipeline System (TAPS), where it would be routed to the Valdez tanker terminal.

Ice-breaking tankers are still being considered as a viable option to pipelines in many of the planning areas in Alaska including the western portion of the Chukchi Sea and Hope Basin. Tankering may be economically viable and may be the form of transportation selected by industry in Alaska as it was selected, for example, in the North Sea for marginal fields in their initial stage of production.

Anticipated OCS production is not likely to exceed TAPS capacity and is expected to actually replace production from the Alaskan North Slope (ANS) which is estimated to decline rapidly in the late 1990's.

The TAPS began transporting crude oil from the ANS to Valdez on June 10, 1977. TAPS is a 48-inch diameter line designed to have a potential capacity of 2.0 million barrels per day, although 1.7 million barrels per day has been set as the maximum efficient rate by the Alaska Oil and Gas Conservation Commission.

The terminal at Valdez is able to handle four tankers at one time and has an average turnaround time of 24 hours. TAPS is presently delivering crude oil from Prudhoe Bay which initially had an estimated 9.6 billion barrels of recoverable oil reserves and from Kuparuk which had an estimated 1.6 billion barrels of recoverable oil reserves.

There is currently no system available to transport natural gas from the Prudhoe Bay area of the Alaska OCS to the contiguous United States. Based on current cost/price relationships and foreseeable technological advances, the gas resources estimated for the Beaufort Sea and Chukchi Sea planning areas are assumed in the SID analysis to be uneconomic. The Alaskan Natural Gas Transportation System (ANGTS) had been proposed to carry North Slope and Canadian natural gas to the lower 48 States. The pipeline is currently delivering gas from north of Calgary, Alberta to Iowa and Oregon. However, the Alaskan and northern Canadian sections of the pipeline remain unbuilt. Sponsors of the ANGTS have announced delay in the target date for completion of the line, citing inability to obtain funding. Some analysts argue that the pipeline's estimated cost makes completion of the project economically impractical. Others contend that current economic conditions have only delayed its completion. If completed, the pipeline would carry North Slope and Canadian natural gas to markets as far away as Chicago and San Francisco. Another pipeline, the All Alaska Natural Gas Pipeline, has been proposed to transport the North Slope gas to Kenai, Alaska for processing and transportation.

In the absence of a pipeline, other gas transportation systems are being considered including liquefaction of natural gas (LNG) and conversion of gas to methanol. Industry indicates that the technology exists to use gathering lines to a grounded barge with prefabricated facilities for processing, storage, and utilities and to then tanker LNG to a terminal. The major problems lie in operating tankers in a hostile environment. Tankers designed with ice breaking capability and otherwise modified for operations in an arctic environment are believed to be feasible.

LNG terminals could also be mounted on an offshore platform, although offshore fixed storage and loading facilities are only in the conceptual stage of development. The technology for an LNG transfer system from a fixed platform to floating storage or tankers appears to be available for Alaskan offshore waters but has not been proven. Onshore LNG terminals now exist in Quincy, Massachusetts; Cove Point, Maryland; and Savannah, Georgia.

The second oil transportation scenario for Alaska encompasses possible production within the St. George Basin, Norton Sound, Navarin Basin and the North Aleutian Basin planning areas. Transportation projections for these planning areas feature a series of gathering and trunk lines feeding into a central offshore or onshore terminal. Ice-breaking shuttle tankers would be used to move the crude to an ice-free deepwater port on the Southern Alaskan peninsula for transshipment. As an alternative, it is possible that potential OCS production from the North Aleutian Basin would be piped directly to the transshipment terminal.

As another alternative, industry is currently indicating that ice-breaking tankers could be used to transport the product directly to market, without using any shuttle tankers, which minimizes the problems with potential spills associated with unloading and reloading. The vessels can use a variable pitch propeller system, which will give them power in the ice and speed in the open water.

The transportation of crude oil from OCS operations in the Bering Sea would require the construction of new tanker facilities. While weather conditions are severe in these areas, sea conditions would not preclude the use of conventional tankers during most of the year. The supply of tankers is not expected to pose a constraint on development of leases issued during the 1986-1991 time period.

The third scenario includes the Shumagin Basin, Kodiak, Cook Inlet, and Gulf of Alaska planning areas. If production from these OCS areas were to occur, it would likely be moved through subsea pipelines to storage facilities prior to being tankered directly to market. Some new tanker facilities would likely be required.

III. Transporting Landed Resources to Refinery and Demand Centers

The existing refinery and continental pipelines system in the Gulf Coast imposes no constraint on processing and distribution of anticipated OCS production. It is assumed that all Gulf OCS production will be landed in the Gulf and processed and distributed in response to market conditions. For a variety of reasons, more detailed analysis is required for West Coast OCS production.

Transportation networks do not pose a major constraint to further subarctic OCS production, as they will be modified to serve economically viable hydrocarbon discoveries. The availability of current transportation networks will, in fact, facilitate the development of OCS resources which can make use of those networks. The factors restricting transportation network availability and, potentially, OCS production, will be the environmental and economic costs associated with establishing and operating the necessary transportation systems. Transportation costs and availability are carefully considered when evaluating the economic feasibility of every hydrocarbon discovery. Resource development will not occur unless the hydrocarbons can be economically transported to regional and national markets.

As an example, the economic benefits analysis presented in Appendix F of this SID does not include benefits from the production of natural gas resources in the Beaufort or Chukchi planning areas due to expected high production costs, consisting largely of transportation costs. In addition, the economic benefits analysis in Appendix F arrives at the net economic value of production of the oil and gas resources by subtracting from it the costs of developing and transporting those resources to market. Environmental costs associated with transportation of production are taken into account in the calculation of social costs in Part II.B of this SID and Appendix G and in the estimation of environmental sensitivity in Part II.C of this SID and in Appendix I.

Specific assumptions are made to allocate OCS oil production between West and Gulf Coast refineries. Forecast Petroleum Administration for Defense District (PAD) V (Alaska, Hawaii, Washington, Oregon, California, Arizona, and Nevada) refining capacity is used as an upper bound on deliveries of OCS oil. Both onshore and OCS production from California, Oregon, and Washington are allocated to PAD V refineries. Alaska OCS oil and other Alaskan oil are allocated to excess PAD V refinery capacity proportionately. The excess PAD V refinery capacity is calculated by subtracting the estimated production in California, Oregon, and Washington from the PAD V refining capacity. Most Alaskan and West Coast production not refined in PAD V is expected to be delivered to the Gulf Coast area for refining. An extensive pipeline system originating in the Gulf along with transport of refined products by barge and tanker will allow delivery to market centers throughout much of the country.

In 1984, there were 47 operating refineries in PAD V with 4 idle refineries. Six refineries in PAD V became inoperable between 1980 and 1984. The 47 operating refineries in PAD V produced 2.460 million b/d of products during 1984 and the total capacity of operating and idle refineries was 2.995 million b/d. The decline in PAD V refinery capacity during 1984 was consistent with a nation-wide pattern of reduced refinery capacity which started in 1981. Over the 5-year period, national refining capacity dropped by almost 22 percent (Oil and Gas Journal, March 18, 1985).

Explicit assumptions concerning future refining capacity and demand for petroleum in PAD V will provide a basis for estimating how much West Coast OCS oil will likely be refined and consumed on the West Coast and how much West Coast OCS oil will likely be shipped to the Gulf Coast for refining and use. The Department of Energy was consulted to obtain a forecast of future petroleum consumption in PAD V. Across all petroleum consuming sections the demand for refined products in PAD V is estimated to be approximately 2.75 million b/d in the year 2000 and 2.6 million b/d in the year 2010.

The PAD V consumption forecast must be augmented by a forecast of future export of refined products to have an estimate of total future PAD V refining capacity. In 1984, PAD V had net product export of 122.7 thousand b/d. Thus, net exports amount to approximately 4.5 percent of total refinery production. Increasing the forecast demand for petroleum production in the years 2000 and 2010 by 4.5 percent

would increase the refinery production estimate to 2.87 million b/d in 2000 and 2.7 million b/d in 2010. The Department of Energy has not forecast expected future product exports from PAD V. Estimates of approximately 2.9 million b/d in 2000 and 2.7 million b/d in 2010 will be used in allocating Alaskan and West Coast OCS oil between PAD V refineries and refineries in the Gulf of Mexico.

It is perhaps, relevant to note that the estimate of 2.9 million b/d for the year 2000 is slightly less than the total capacity of operating and idle refineries in PAD V during 1984. Between 1984 and 2000 PAD V refining capacity is assumed to equal 2.9 million b/d and a straight line decline is used between 2000 and 2010.

The estimated total production in PAD V exceeds expected PAD V refining capacity past the year 2010. Transportation of part of the PAD V surplus by pipelines is expected. There are presently three proposed pipelines in various stages of the complex procedures for obtaining necessary permits. The proposed projects include the All-American Pipeline from Santa Barbara, California, to Midland, Texas, with a 300,000 b/d capacity; the Pacific-Texas pipeline from Long Beach, California, to Midland, Texas, with a proposed throughput of 900,000 b/d; and the expansion of the existing Four Corners pipelines to a proposed capacity of 150,000 b/d from Long Beach to New Mexico. For purposes of this analysis, it is assumed that pipeline transportation for PAD V oil will be operational by 1995. The capacity of pipeline transportation assumed in this analysis is 500,000 b/d.

Demonstration of the method for allocating Alaskan oil to West and Gulf coast refineries is provided by explaining the calculations for the year 2000 which use $29/barrel resource estimates. PAD V refining capacity is estimated to be 2.9 million b/d. Additionally, 0.5 million b/d of pipeline capacity is assumed. Production for the Pacific OCS (all three California planning areas plus Washington and Oregon) is estimated to be 0.377 million b/d and onshore production is estimated to be 2.384 million b/d. Subtracting these estimates of 2000 production from the estimate of PAD V refining and pipeline capacity provides an estimate of surplus PAD V refining capacity--0.639 million b/d. This surplus is allocated between Alaska OCS and Alaska onshore oil proportionately which results in 0.048 million b/d of the estimated 0.134 million b/d being allocated to PAD V refineries with the rest going to the Gulf of Mexico PAD III refineries. Similar calculations were made for each year between 1995 and 2010. After 2010 all Alaskan OCS oil production can be refined in PAD V. Summing across the period 1995 - 2020 produces an estimate of the total amount of Alaska OCS oil that is allocated to West and Gulf Coast refineries. The results for $29/barrel oil price estimates are that 486 million barrels of Alaska OCS oil production can be delivered to PAD V refineries and 270 million barrels will have to be shipped to PAD III for refining.*

In the past, concern has been expressed that the low gravity, high sulfur crude oil found on the California OCS and the low gravity oil from the Alaska North Slope could not be refined in most California refineries without violating California air quality standards. Retrofitting refineries to allow operations to meet air quality standards while processing lower quality crudes is expensive. Still, some California refineries are currently being modified to handle the lower quality crude oil expected to be produced in the near future.

* When $24/barrel resource estimates are used in these calculations, the results are that all Alaskan and Pacific OCS oil production would most likely remain on the West Coast.

No additional refineries are expected for the Gulf of Mexico region or the Atlantic Coast. In 1982, refineries in the Gulf were operating at approximately 65 percent of total capacity; Atlantic Coast refineries are currently (October 1984) operating at about 66 percent of capacity. Some retrofitting of existing facilities has occurred in the Gulf to accommodate low quality Alaska and California crude oil.

APPENDIX K

FAIR MARKET VALUE

FAIR MARKET VALUE

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Appendix K

FAIR MARKET VALUE

I. Introduction

The Secretary of the Interior, in formulating an Outer Continental Shelf (OCS) oil and gas leasing program, is required to assure the receipt of fair market value for the lands leased and the rights conveyed by the Federal Government. Such an assessment requires an analysis of the term "fair market value." This is a term with both legal and economic meaning. "Market value" has its origin in the world of economics--the marketplace, an exchange of goods and services at a price determined by a willing buyer and a willing seller. The term "fair" is more elusive and is subject to interpretation. The question arises as to whether "fair" modifies the term "market" or the term "market value." An examination of both meanings of the term, however, is not mutually exclusive; rather, it is sequential: (1) What are the determinants of a fair market? (2) Does the existence of a fair market assure the receipt of fair market value?

One of the many factors the Secretary must weigh in creating a leasing program is the principle that "leasing activities shall be conducted to assure receipt of fair market value for the lands leased and the rights conveyed by the Federal Government." (See 43 U.S.C. 1344(a)(4)1.) This is distinct from the economic principles around which the 5-year program is designed, including maximizing the Nation's income.

This appendix discusses how the Department assures receipt of fair market value and the economic concepts and mechanisms which provide the foundation for generating fair market value for OCS oil and gas leases. Section II presents the legal requirements and judicial interpretations of fair market value under the OCS Lands Act. Section III focuses on the OCS oil and gas lease market and the role of competition in generating value. Section IV discusses the factors and methodology which are considered by both Government and the private sector in evaluating OCS oil and gas for potential exploration and development. Section V discusses the Government's procedures to assure receipt of fair market value and Section VI indicates the context in which the fair market value requirement must be considered with the other requirements of the OCS Lands Act governing the management of these resources. It discusses the issue of fair market value not being synonymous with maximization of government receipts.

II. Legal Requirements and Judicial Interpretations of Fair Market Value

Section 18(a)(4) of the OCS Lands Act requires the formulation of an OCS oil and gas leasing program consistent with the following principle:

> Leasing activities shall be conducted to assure receipt of fair market value for the lands leased and the rights conveyed by the Federal Government.

Section 2(o) of the act defines "fair market value" as it applies to the value of "any mineral" but not to the value of the lands leased and the rights conveyed. The Conference Report on S.9 states that the term as so defined "is only used in the Act in relation to the purchase and distribution of oil and gas under Section 27." That section pertains to Federal purchase and disposition of royalty oil and gas in kind. "Fair market value," as it applies to lands leased and rights conveyed, is thus not explicitly defined by the OCS Lands Act.

In the 1982-1987 5-year program, the Secretary adopted the following definition:

> "Fair market value" is defined as the amount in cash, or in terms reasonably equivalent to cash, for which in all probability the property would be sold by a knowledgeable owner willing but not obligated to sell to a knowledgeable purchaser who desired but is not obligated to buy.

The U.S. Court of Appeals for the District of Columbia Circuit was asked to determine whether the Secretary could meet the statutory requirement "to assure receipt of fair market value for the lands leased and the rights conveyed" by OCS oil and gas leases, in light of the fact that the "accelerated rate of leasing might ordinarily result in less intense competition and lower bids for some tracts." (See California v. Watt, 712 F.2d at 584, U.S. Court of Appeals, District of Columbia Circuit, July 5, 1983.) The court ruled that, despite the lower bids expected, "the proposed evaluation process, coupled with the Secretary's reasonable reliance on the integrity of the competitive bid process, is sufficient to assure that the fair market value is received. The statute requires nothing more." (See 712 F.2d at 608.)

I. Characteristics of the OCS Lease Market

Drawing upon the definition of fair market value provided by the Interagency Land Acquisition Conference (Interagency Land Acquisition Conference, Uniform Appraisal Standards for Federal Acquisition, 1973) which states in part: "Fair market value is defined as the amount in cash . . . for which in all probability the property would be sold by a knowledgeable owner willing but not obligated to sell to a knowledgeable purchaser who desired but is not obligated to buy.", we analyze its application to the OCS lease market in terms of:

- what is the "property" being sold; and
- what characterizes knowledgeable buyers and sellers willing but not obligated to buy or sell.

The property (product) being sold in the OCS lease market, characterized by numerous private buyers and one public seller, is the right to explore, develop, and produce oil and gas on designated offshore lands in an expeditious manner and in accordance with other restrictions imposed on the lessee, some of which may be imposed after the lease is issued. There is no guarantee that the property leased will contain oil and gas; if oil and gas are found and the quantities discovered are economic to produce, their production and the resulting cash flows may extend from 5 to 25 years into the future.

The structure of the lease market for the exchange of these rights between buyers and sellers is established by the OCS Lands Act.

The act provides that oil and gas leases are to be sold by competitive sealed bidding and thus establishes the requirement of a competitive market structure to generate the value of OCS oil and gas leases. In practice, the determination of fair market value for the high bid is based only on the amount of the bid (relative to the MMS quantitative measures of bid adequacy) given that the high bidder is qualified to conduct OCS operations.

One characteristic of a competitive (i.e., fair) market is the ability of the market to generate a competitively determined value among buyers and sellers not operating under coercion or restraints to entry and without the imposition of artificial barriers to competition. A competitive market is thus characterized by "knowledgeable buyers and sellers willing, but not obligated to buy or sell."

Knowledgeability of buyers and sellers in a competitive market does not equate with a perfect and equal level of knowledge, rather, it pertains to buyers and sellers having reasonable knowledge of the relevant facts. In the case of OCS oil and gas leases, there are high levels of uncertainity associated with the variables affecting the value of a lease (section IV discusses this in more detail). In addition, interpretation of that knowledge differs from bidder to bidder and from the Government to the private sector. If there are no artificial constraints or barriers to acquiring that knowledge, the

competitive market mechanism will not be hampered. The Government, as seller, combines its knowledge of the working of the market along with geological, geophysical, engineering, and economic interpretations to assure fair market value.

Markets in which coercion or entry restraints are operative will generate values which may be artificially constrained. The OCS Lands Act provides for a review prior to the final award of leases to help assure that the OCS market is free from collusion. Under section 8(c), the Federal Trade Commission and the Antitrust Division of the Department of Justice review pending lease awards for effects on competition, and the Attorney General is authorized to make recommendations to the Secretary to prevent any situation inconsistent with the antitrust laws. Based on such recommendations or on his own motion, the Secretary may refuse to accept a high bid or issue a lease. (These reviews have never identified collusive behavior among bidders for OCS leases.)

In the OCS lease market, the potential competition for individual leases is an important factor in bid formulation. Bidding theory recognizes that, in addition to the tract-specific evaluations (discussed in section IV), expected competition is a factor that should be taken into account in bid formulation (F. C. Copen, R. V. Clapp, and W. M. Campbell. "Competitive Bidding in High Risk Situations," Journal of Petroleum Technology, 23, 1971, pp. 641-653, and J. G. Riley and W. F. Samuelson. "Optimal Auctions," American Economic Review, 71, June 1981, pp. 381-392). Although it may seem counterintuitive, theory indicates that bidders generally should reduce their bid when the expected number of competitors increases beyond two. Thus, the tendency for the high bid to increase as competition increases is, at least in theory, not necessarily due to each bidder bidding higher, but rather because there are more bids from which the high bid will emerge.

Both theoretically and empirically, the high bid tends to increase as the number of bids increases on a tract with a given value estimate. The OCS Task Force Report on Fair Market Value (February 1983) concluded, based on the historical average of recorded competition (as measured by the number of bids received), that when three or more prospective buyers submit a bid for an oil and gas lease, competition in the marketplace is sufficient to assure a fair return to the seller. (This conclusion was qualified in the event that a sale had an average number of bids in excess of three. Also the number of bids rule is applied to wildcat and proven tracts, on which there is a reasonable absence of asymmetry of information.)

The Secretary's "reasonable reliance on the integrity of the competitive bid process" to generate fair market value is reflected in the procedures used to determine bid adequacy and assure fair market value on a lease-specific basis. The following section examines the method and factors which are considered in assessing value for OCS oil and gas leases.

Factors Affecting Value: Methodology Used in Determining Value

The Interagency Land Acquisition Conference went on to state regarding fair market value that "In ascertaining that figure, consideration should be given to all matters that might be brought forward and reasonably be given substantial weight in bargaining by persons of ordinary prudence . . . ."

There are a series of factors exogenous to the OCS lease market, itself, which are considered in evaluating specific tracts or in "ascertaining that figure." The standard methodology used in petroleum evaluations is a probabilistic discounted cash flow model. The methodology incorporates assessments of all major factors affecting the value of a lease over its potential life; namely, the timing of exploration and development activities, future prices of oil and gas, costs of exploration, development and production, inflation rates, and tax considerations.

Furthermore, all of the major inputs used in assessing the value of OCS oil and gas leases change over time. For example, knowledge of the physical or geological nature of the resource, based on geological and geophysical data, changes as information is acquired from leases and permits, thus affecting positively or negatively the value of tracts remaining to be leased. The costs and the timing of exploration, development, and production are influenced by the location of the resource--whether it is located in remote locations with no current means of transportation or in unusually deep water hundreds of miles from shore. The value of OCS oil and gas leases is also influenced by current and expected future prices of the end product--oil and gas. These prices are critical in determining the amount that bidders will pay for OCS leases, regardless of the size and timing of tract offerings. The domestic price of oil and gas is largely determined in the international market, strongly influenced by the OPEC nations because of their control over large quantities of reserves. Individual company's investment portfolios and capital budgets are also factors which they consider in valuing OCS oil and gas leases.

The end result of these assessments is a range of potential values for an oil and gas lease which reflects the uncertainties of the input factors. From the buyers' point of view, the residual value resulting from this type of evaluation represents the potential profitability of a lease. From the Government's point of view, the measures developed using the same type of technique result in an estimate of a value which, on a lease-specific basis, is used as an initial step in estimating the price (i.e., high bid) which the Government could accept while meeting the fair market value requirement. Simultaneously, this approach provides for the consideration of important factors to "be given substantial weight" in determining market value.

The competitive sealed bidding process of the OCS lease market is the market mechanism which generates a fair market value at a specific point in time (i.e., a sale). However, there are possibilities in the OCS lease market which could allow bids to be submitted which, without the exercise of a prudent assessment by the Government, could result in less than a fair market value. Where information asymmetry exists, such as on drainage and development tracts on which the adjacent owner has privileged information or on wildcat and proven tracts that involve development technologies unique or limited to selected companies, the corresponding bid may be skewed and other parties may choose not to bid. In order to assure fair market value as the law requires and the courts have interpreted, the Secretary has developed a set of procedures which reflect an understanding of the workings of the OCS lease market in generating values and bids. He has structured the procedures to assure receipt of fair market value by relying on the fair market to generate fair market value and by relying on Government evaluations to assure that market values being generated for certain categories of tracts are indeed fair; otherwise, the high bids are rejected and the tracts reoffered at a later date.

The Government, as seller of the leases and controller of the rate of leasing (size and timing of lease sales), may have some capability to influence the overall level of bidder activity (competition) in the OCS oil and gas lease market. Section V examines this influence and the procedures established for assuring fair market value.

The assurance of fair market value is relevant to lease sale formulation only to the extent that the rate of leasing can be shown to result in a market that does not operate competitively. For example, since bidders on OCS tracts must gather data, prepare bids, and be ready to conduct exploration efforts, sale timing could limit their ability to participate, thus hampering competition and the receipt of fair market value. Also, if sales were too rapid or made on very short notice, competition could be hampered because of industry's inability to budget or plan for lease sales, including the acquisition of geological and geophysical data and evaluation of tracts.

One important methodology used in formulating a leasing schedule has as its objective the maximization of national income from leasing activities. (See Appendix F.) This conceptual framework and the factors which it takes into consideration require an understanding of existing and projected market conditions affecting OCS oil and gas leasing rates. Fair market value assurance, however, takes the market conditions as given and has as its primary objective the assurance that the conditions within the OCS oil and gas lease market, itself, generate a fair return to the Government. Procedures to assure the receipt of fair market value which reflect an understanding of the competitive mechanism of the OCS lease market are discussed in the following section.

V. Discussion of Procedures to Assure Fair Market Value

Throughout the history of the OCS leasing program, assuring receipt of fair market value has been a constantly evolving process. In the late 1960's, the Department of the Interior began placing an independent cash value on every tract offered for lease. During the mid-1970's, the Department began using market information in the bids received along with the Government's estimated independent tract evaluation to make accept/reject decisions. This gave recognition to the concept that fair market value, as a price in a competitive market, should reflect values offered by prospective buyers operating in the economic climate prevailing at the time of the lease sale as well as the seller's value.

In July 1982, a Department-wide task force was established to develop and test various methods for determining bid adequacy in light of the Secretary's legal requirement to assure receipt of fair market value in conjunction with the new leasing program proposed at that time. In February 1983, the Department adopted the recommended procedures of the task force which consisted of a two-phase bid adequacy process which used tract classification and actual bid data to evaluate tracts receiving bids in order to determine which tracts required detailed analysis and which tracts the competitive market forces could be relied upon to assure receipt of fair market value. Phase 1 includes market-oriented evaluation criteria for accepting some bids on some blocks and determining what other bids will receive further evaluation in Phase 2. Phase 1 is composed of criteria designed to partition blocks receiving bids into three general categories:

- those receiving bids which MMS has identified as being nonprospective;
- those where opportunities for strategic underbidding, information asymmetry, collusion, and other noncompetitive practices might most likely occur and where the Government has detailed and reliable data; and
- those where the competitive market forces can be relied upon to assure fair market value.

Phase 2 provides for the application of criteria designed to further determine bid adequacy on a block-specific basis and uses independent Government evaluations in addition to the bid data to determine bid acceptance/rejection.

In 1984 and 1985, modifications were made to the OCS bid adequacy procedures to incorporate knowledge gained from their actual use in areawide lease sales. On the surface, there has been an observable overall decrease in the average bonus bid per acre in recent years. This trend actually began in 1982 in tract selection-type sales. There has also been an increase in the number of one-bid tracts. Analysis of these observations was made to assess their cause. While the per acre bonus declines have been due to a myriad of factors, the most significant ones appear to be the decrease in the expected price of oil and the overall quality and location of tracts being offered for

lease. A 20-percent drop in the real world price of oil, along with projections of lower rates of future price growth, have significantly influenced the present value of tracts being offered. Further, the sales and leasing of tracts in areawide sales have seen industry moving into deepwater, high-cost, high-risk areas of mature OCS planning areas and into high-cost, high-risk frontier areas--a trend which barely began when tract selection-type sales were held. Market forces are operating to reflect these conditions.

Because many of the tracts offered for sale recently have marginal potential for hydrocarbon resources (they have been offered before and not leased or have been leased and relinquished), more one-bid tracts have been generated. In order to continue to assure fair market value within the changing conditions of the OCS lease market, technical adjustments in the bid adequacy procedures have been made as a result of the Government's analysis of these changing market conditions. For example, in the initial areawide lease sales a geomean rule was used as one of the market-oriented bid criteria for bid acceptance in Phase 1. This rule provided for the acceptance of bids on wildcat and proven tracts if the geometric mean of the bids received on the tracts was greater than the median of the geometric means of bids received on prospective wildcat and proven tracts. This rule is no longer used as a market-oriented criteria for bid acceptance based on analysis indicating that the geometric mean is a considerably less useful statistical measure of bidding behavior when there is a greater proportion of tracts receiving fewer bids. As a result, more tracts now receive further evaluations. Nevertheless, the basic conceptual framework of the bid adequacy procedure has not been modified and satisfies the legal requirement of assuring fair market value by instituting a process which assesses the workings of the market on a tract-specific basis in determining a fair return. Reliance is placed on the marketplace as well as the Government's independent assessment.

Based on analyses, studies, and experience with the oil and gas leasing market, categories of tracts for which the bids may not assure fair market value are subjected to additional independent Government evaluation. All evaluations incorporate the use of the latest geological, geophysical, and economic evaluation methodologies and account for the inherent uncertainties of all the major variables. The recent (March 26, 1985), GAO study of MMS's procedures for tract evaluation titled "Interior Has Taken Steps to Improve the Adequacy of Data Used for Making Outer Continental Shelf Leasing Decisions," recognized MMS's continuing improvement of its procedures and data for tract evaluation purposes.

The following procedures for OCS bid adequacy are currently in effect for all OCS lease sales. They provide for the application of criteria in a two-phased process for bid adequacy determination.

Phase 1

Phase 1 provides for the application of criteria designed to partition tracts receiving bids into three general categories:

- those receiving bids which MMS has identified as being nonprospective (nonviable),
- those where opportunities for strategic underbidding, information asymmetry, collusion, and other noncompetitive practices might most likely occur and where the Government has the most detailed and reliable data; and
- those where the competitive market forces can be relied upon to assure fair market value.

Based on these categories, the following three Phase 1 criteria are applied to all tracts receiving bids:

1. High bids on all tracts classified by MMS as being either development or drainage will be referred directly for further evaluation in Phase 2.
2. All legal high bids for tracts judged by MMS not to be located on a viable prospect will be accepted.
3. After screening for anomalous bids,1/ all legal high bids will be accepted for wildcat and proven tracts receiving three or more bids and more than the average number of bids for viable wildcat and proven tracts receiving one or two adjusted bids and all wildcat and proven tracts receiving three or more adjusted bids, i.e., whichever is more.

After applying the Phase 1 criteria for bid acceptance, the Regional Director, if he should determine that an unusual bidding pattern exists and affects tracts which would be accepted by the Phase 1 criteria, and if the unusual bidding pattern can be documented, has the discretionary authority, after consultation and coordination with the Solicitor, to pass those tracts so identified to Phase 2 for further analysis.

Phase 1 is conducted tract-by-tract and is generally completed within 3 days of the bid opening.

Phase 2

Phase 2 provides for the application of criteria designed to further determine bid adequacy on a tract-specific basis. All prospective wildcat and proven tracts which are not accepted in Phase 1 are passed to Phase 2 for further evaluation. After further mapping and/or analysis are completed in Phase 2, the viability determinations of these tracts can be reviewed, using the same procedures to determine viability that were applied in Phase 1.

1/Anomalous bids will not be included in the bid number in either Phase 1 or Phase 2. Anomalous bids include all but the highest bid submitted for a tract by the same company (bidding alone or jointly) and the lowest bid on a tract when it is less than one-eighth of the next lowest bid. The "one-eighth rule" can exclude no more than one bid for a given tract.

Those wildcat and proven tracts which are subsequently determined to be nonviable can be eliminated from the set of tracts undergoing a full-scale MONTCAR run and the high bids on them accepted. All of the remaining tracts, including all drainage and development tracts, receive further evaluation by comparing the high bids with the mean range of values (MROV) and the Discounted Mean Range of Values (DMROV). All tracts in Phase 2 which received three or more adjusted bids and wildcat and proven tracts which received two adjusted bids will be compared to the Geometric Average Evaluation of the Tract (GAEOT). In addition, if in the judgment of the Regional Director a tract is or may be subject to drainage, the relevant costs due to delays associated with bid rejection are considered in the bid adequacy determination. While it is expected that most evaluations would be undertaken based upon geological and geophysical data and analyses available at the time of the sale, additional analyses can be undertaken postsale at the discretion of the Regional Director.

The bid adequacy recommendations developed in Phase 2 are normally completed sequentially over a period ranging between 3 and 60 days after the sale. The Regional Director has the discretionary authority to extend this period up to 90 days after the sale when necessary to assure a thorough evaluation.

Statistics on the use of these procedures in areawide sales (April 1983 through October 1984) indicate that 58 percent of the tracts receiving bids (68 percent of the high bids) were accepted using Phase 1 criteria, and 42 percent were passed to Phase 2 for further evaluation. Seven percent of the total tracts receiving bids or 16.6 percent of the tracts passed to Phase 2 for further evaluation were rejected.

Table 1 contains statistics on the use of the two-phase bid adequacy procedures since they were adopted in 1983. In the 1983-1984 time period, 2,681 tracts received bids in areawide lease sales; 1,542 of these tracts were leased using Phase 1 criteria; 1,141 tracts were passed to Phase 2 for further evaluation. One hundred and ninety tracts with high bids of $389 million were rejected because they were inadequate. Two tracts were reneged with high bids of $3.725 million. The 2,489 tracts leased yielded a return of $9.8 billion in bonuses for the lands leased and the rights conveyed.

Minimum Bid Requirements

As part of the last 5-year program decision on fair market value, the Department increased the minimum bid from $25 to $150 per acre. In conjunction with the two-phased procedures, the minimum bid may help to assure fair market value by substantially increasing the bonus amounts bid on many one-bid tracts. The minimum bid represents an across-the-board Government evaluation standard with which all high bids are compared--it provides the initial step in the overall bid adequacy process.

The analytical basis for the change was an empirical and theoretical study which focused on the effects of a higher minimum bid on bidding behavior and Government receipts for medium-sized sales which were scheduled for 1982. (Marshall Rose, Minimum Dollar Bid Requirements for Moderately-Sized OCS Lease Sales: The Case of 1982 Offerings, U.S. Department of the Interior, Office of Policy Analysis (OPA), December 1981.) A bidding model was developed and originally applied to 1,689 tracts offered for lease between

New Fair Market Value Procedures Statistics

Lease Offering	Mid-Atlantic (April 1983) Number of Tracts	Mid-Atlantic (April 1983) High Bids (000)	Central GOM (May 1983) Number of Tracts	Central GOM (May 1983) High Bids (000)	So.-Atlantic (July 1983) Number of Tracts	So.-Atlantic (July 1983) High Bids (000)	Western GOM (August 1983) Number of Tracts	Western GOM (August 1983) High Bids (000)	California Sale 73 Number of Tracts	California Sale 73 High Bids (000)	Eastern GOM (January 1984) Number of Tracts	Eastern GOM (January 1984) High Bids (000)	Total Number of Tracts	Total High Bids (000)
Total of Tracts Receiving Bids	40	$71,141	656	$ 3,469,215	11	$13,362	436	$1,549,262	8	$16,022	156	$310,586	1,307	$6,230,686
Phase 1														
Tracts Accepted By														
Criterion 1	3	$ 3,620	245	$ 943,020	4	$ 4,060	138	$392,633	2	$ 1,930	70	$112,817	462	$1,458,080
Criterion 2 only	2	4,510	73	936,082	0	0	55	358,647	1	3,131	13	100,171	144	1,402,541
Criterion 3	17	44,459	127	1,094,246	3	5,171	95	514,244	-	-	31	56,114	273	1,714,234
(unduplicated) Criteria 2 & 3	19	48,969	200	2,030,328	3	5,171	150	872,891	1	3,131	44	156,285	417	3,116,775
Subtotal (a)	22	52,589	445	2,973,348	7	9,231	288	1,265,524	3	5,061	114	269,102	879	4,574,855
Percent of Total(%)	55	74	68	86	64	69	66	82	38	32	73	87	67	73
Tracts Passed to Phase 2														
Drainage or Dev.	0	$ 0	53	$ 272,587	0	$ 0	33	$ 135,162	4	$ 9,854	0	$ 0	90	$417,603
Remaining Viable Tracts in Ph. 1	18	18,552	158	223,280	4	4,131	115	148,577	1	1,108	42	41,484	338	437,132
Subtotal	18	18,552	211	495,867	4	4,131	148	283,739	5	10,962	42	41,484	428	854,735
Percent of Total(%)	45	26	32	14		31	34	12	63	68	27	13	33	14
Phase 2														
Tracts Evaluated	18	$18,552	211	$ 495,867	4	$ 4,131	148	$ 283,739	5	$10,962	42	$ 41,484	428	$854,735
Accepted	15	15,821	178	394,258	4	4,131	120*	239,169*	5	10,962	42	41,484	364	705,825
Rejected	3	2,731	33	101,609	0	0	28	44,570	0	0	0	0	64	148,910
Rejected as Percent of Total (%)	8	4	5	3	0	0	6	2	0	0	0	0	5	2

* The lessee refused to accept two tracts which received high bids of $3,725,000.
Criterion 1 is the non-viable prospect rule.
Criterion 2 is the number of bids rule.
Criterion 3 is the median of the geometric average rule.

Lease Offering	Sale 83 Navarin (April 1984) Number of Tracts	Sale 83 High Bids (000)	Sale 81 Central GOM (April 1984) Number of Tracts	Sale 81 High Bids (000)	Sale 84 Western GOM (July 1984) Number of Tracts	Sale 84 High Bids (000)	Sale 87 Diapir (August 1984) Number of Tracts	Sale 87 High Bids (000)	Sale 80 California (October 1984) Number of Tracts	Sale 80 High Bids (000)	Total Number of Tracts	Total High Bids (000)
Total of Tracts Receiving Bids	186	$631,228	529	$1,446,585	402	$945,717	232	$877,131	25	$66,231	1,374	$3,966,892
Phase 1												
Tracts Accepted												
Criterion 1	68	$204,025	155	$319,586	91	$175,252	179	$524,003	7	$ 7,644	500	$1,230,510
Criterion 2	51	323,577	45	295,392	32	134,594	33	315,029	2	10,995	163	1,079,587
Subtotal (a)	119	527,602	200	614,978	123	309,846	212	839,033	9	18,639	663	2,310,097
Percent of Total (%)	64	84	38	42	31	33	91	96	36	28	48	58
Tracts Passed to Phase 2												
Drainage or Dev.	0	$ 0	40	$46,432	35	$10,209	1	$5,167	3	$23,709	79	$85,517
Remaining Viable Tracts in Ph. 1	67	$103,625	289	785,174	244	625,662	19	32,931	15	$23,884	634	$1,571,276
Subtotal	67	103,625	329	831,606	279	635,871	20	38,098	18	47,593	713	1,656,793
Percent of Total (%)	36	16	62	58	41	26	9	4	72	72	52	42
Phase 2												
Tracts Evaluated	67	$103,625	329	$831,606	279	$635,871	20	$38,098	16	$47,593	713	$1,656,793
Accepted	61	96,888	253	708,058	238	535,004	19	32,931	14	43,483	585	1,416,364
Rejected	6	6,737	76	123,548	41	100,867	1	5,167	2	4,110	126	240,429
Rejected as Percent of Total (%)	3	1	14	8	10	11	0	1	8	6	9	6

Criterion 1 is the non-viable prospect rule.
Criterion 2 is the number of bids rule.

1978 and 1980. The findings were then extended to tracts scheduled to be offered in 1982 sales to determine the Government revenue effects (focused on one- and two-bid tracts). The quantitative results indicated that increasing the minimum bid amount from $25 to approximately $150 per acre would enhance the expected present value of Government receipts from those sales. The increase in Government receipts was estimated to be in the range of $35 to $50 million per 1,000 tracts leasable in 1982 at a minimum bid of $25 per acre. The results of the analysis also indicated that increasing the minimum bid to $150 per acre would generally not significantly affect competition and the number of tracts receiving bids. It was estimated that the reduction in tracts receiving bids would be only 16 percent for one-bid tracts and 10 percent for two-bid tracts that would ordinarily receive a bid when the minimum was set at $25 per acre.

Figure 1 graphically illustrates the results of the analysis of the estimated effect of increased minimum bids on aggregate Government receipts for one-bidder tracts in 1982 sales. The minimum bid amounts charted are: $0.5 million (equivalent to $86 per acre); $1.0 million (equivalent to $172 per acre); and $2.0 million (equivalent to $344 per acre). The aggregate effect on Government receipts took into consideration the number of tracts not sold in 1982 and the resulting cost of delay, and the higher bids on tracts sold in 1982. The graph illustrates that as the minimum bid is increased to $172 per acre, there was estimated to be a positive incremental effect on Government receipts; beyond that amount, the effect on Government receipts was estimated to decrease.

Recently, MMS analyzed empirical bidding data for 19 OCS lease sales, held offshore Alaska and in the Gulf of Mexico (GOM), to assess the effects of the change of the minimum bid policy on the level of bidding interest.

The analysis found that the effects predicted in the OPA analysis appeared to be largely confirmed in practice, namely that raising the minimum would increase the high bids on the vast majority of affected tracts up to the new minimum. The most striking finding was that in the five GOM sales held prior to the policy change, only 4 percent of the high bids were between $150 to $200 per acre, while only 8 percent of the high bids fell between $150 to $300 per acre. In the four GOM sales held immediately following the policy change, 24 percent of the high bids fell in the $150 to $200 per acre range, while 46 percent of the high bids were between $150 to $300 per acre. (See Tables 1 and 2.) The Alaskan sales showed a similar pattern. Using the $25 per acre minimum, Alaskan sales held prior to the policy change had no high bids in the $150 to $200 per acre interval. After the policy change to a $150 minimum bid, 30 percent of all high bids fell in the $150 to $200 per acre interval. (See Tables 3 and 4.) The decline in the percentage of bids offered in the $300+ per acre range is indicative of the decreasing quality, lower prices, and increased cost/risk associated with the tracts being offered. However, it is not likely that this could fully explain the revised distribution of bids, wherein 30 percent of the tracts received bids within $50 per acre of the revised minimum bid of $150 per acre.

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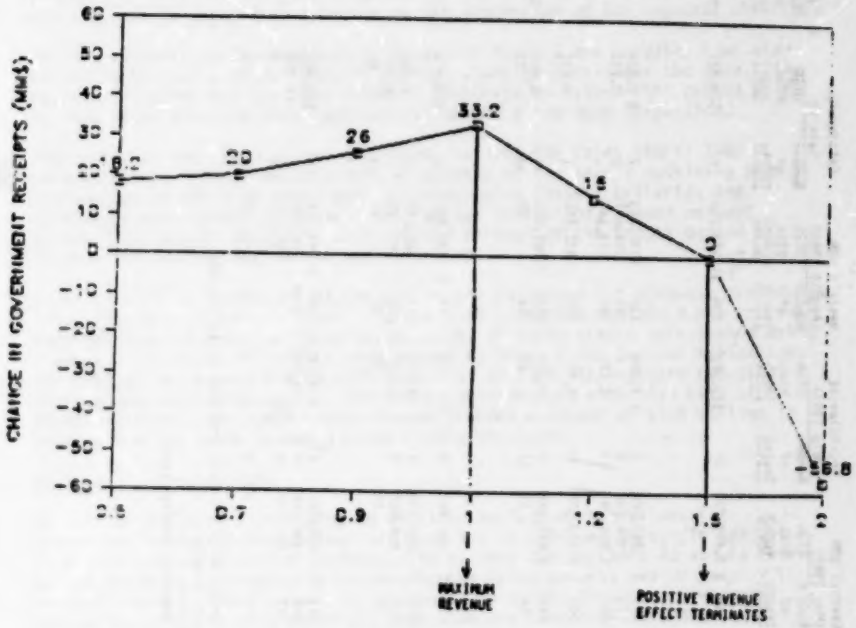
*The lessee refused to accept two tracts included in this total, which were accepted in Phase 2.

EFFECTS ON NET PRESENT VALUE OF FEDERAL BUDGET RECEIPTS ($ MILLIONS) FROM APPLICATION OF MINIMUM BID AMOUNT REQUIREMENTS IN 1982 ON TRACTS RECEIVING ONE BID



Source: Estimates derived from: Marshall Rose, Minimum Dollar Bid Requirements for Moderately Sized OCS Lease Sales: The Case of 1982 Offerings, U.S. Department of the Interior, Office of Policy Analysis, December 1981.

Figure 1

TABLE 1

Distribution of High Bids for Gulf of Mexico Offerings Using $25/Acre Minimum Bid for Bonus Bid, Fixed Royalty Tracts

Offering Date	Total No. High Bids	Percent of Number of All High Bids			
		$25-$150/Acre	$150-$200/Acre	$200-$300/Acre	$300+/Acre
9/30/80 C&E Gulf A-62	77	5	--	1	94
11/18/80 W. Gulf 62	44	5	--	5	91
7/21/81 C&W Gulf A-66	144	8	4	6	82
10/20/81 C&E Gulf 66	59	8	2	3	86
2/9/82 C&W Gulf 67	127	24	6	5	65
Total	451	11	4	4	81

TABLE 2

Distribution of High Bids for Gulf of Mexico Offerings Using $150/Acre Minimum Bid for Bonus Bid, Fixed Royalty Tracts

Offering Date	Total No. High Bids	Percent of Number of All High Bids			
		$25-$150/Acre	$150-$200/Acre	$200-$300/Acre	$300+/Acre
11/17/82 C&W Gulf 69 I	64	--	22	12	66
3/8/83 C&E Gulf 69 II	13	--	31	15	54
5/25/83 C. Gulf 72	635	--	20	17	62
8/24/83 W. Gulf 74	432	--	22	22	56
1/5/84 E. Gulf 79	156	--	49	27	24
4/24/84 C. Gulf 81	529	--	24	29	47
7/18/84 84	402	--	31	25	44
Total	2231	--	25	20	53

TABLE 3

Distribution of High Bids for Alaska Offerings Using $25/Acre Minimum Bid for Bonus Bid, Fixed Royalty Tracts

Offering Date	Total No. High Bids	Percent of Number of All High Bids			
		$25-$150/Acre	$150-$200/Acre	$200-$300/Acre	$300+/Acre
12/11/79 Diapir Fld. BF	25	24	--	8	68
10/21/80 Gulf of Alaska 55	16	63	--	6	31
9/29/81 Cook Inlet 60	6	83	--	--	17
Total	47	45	--	6	49

TABLE 4

Distribution of High Bids for Alaska Offerings Using $150/Acre Minimum Bid for Bonus Bid, Fixed Royalty Tracts

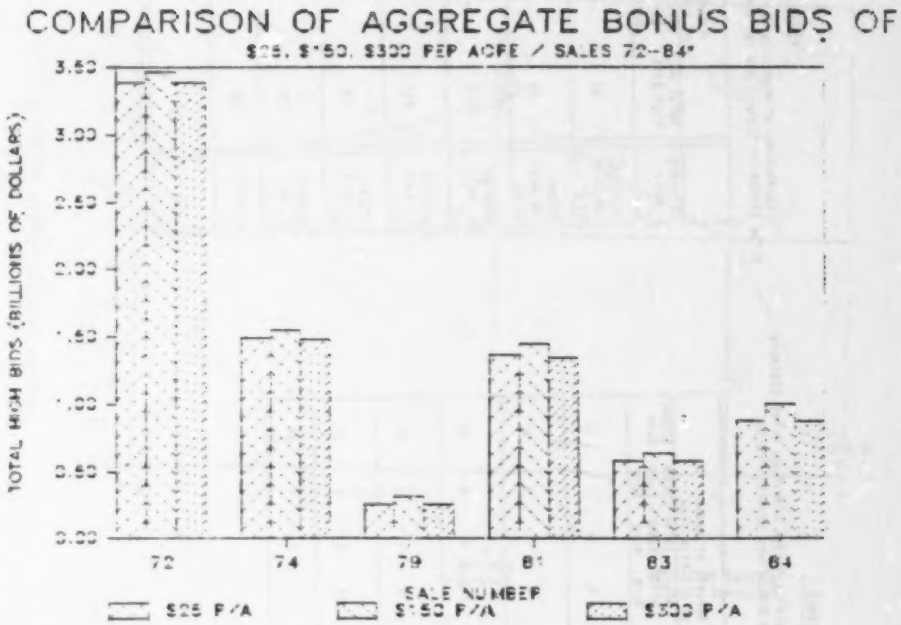
Offering Date	Total No. High Bids	Percent of Number of All High Bids			
		$25-$150/Acre	$150-$200/Acre	$200-$300/Acre	$300+/Acre
10/13/82 Diapir Fld. 71	108	--	19	22	58
3/15/83 Norton Basin 57	54	--	43	13	44
4/12/83 St. Geo. Basin 70	82	--	23	20	57
4/17/84 Sale 83 Navarin	186	--	37	22	41
Total	430	--	30	20	50

Drawing upon the earlier OPA study, further analysis was conducted to estimate the average and total bid amounts which would have been received with a $25 acre minimum and compared the results to empirical bidding data for six OCS lease sales beginning with the first areawide lease sale in the GOM. Figure 2 graphically illustrates for each of the six sales the actual aggregate bonus bids at $150 per acre and the estimated aggregate bonus bids at $25 per acre and $300 per acre. In these sales, the higher minimum bid of $150 per acre was estimated to have increased aggregate bonuses by as little as $50 million and as much as $84 million per sale. The total aggregate bonus increase was $415 million. The bidding results in Sale 79 (Eastern GOM) and Sale 83 (Navarin) did not substantiate earlier concerns that the higher minimum bid might preclude bidding interest in these high-risk and/or high-cost areas.

Additional analysis of the same six sales was conducted to estimate the retrospective revenue effects of a $300 per acre minimum compared to the $150 per acre minimum. The actual bid data from the sales were modified to incorporate assumptions inferred from the previously cited OPA study that such a change would preclude about 75 percent of the high bids observed below $200 per acre and 25 percent of those received between $200 to $300 per acre. The remaining high bids would be raised to the revised minimum bid. The effect of raising the minimum bid from $150 per acre to $300 per acre was estimated to be a decline of about 5 percent in the aggregate high bids received per sale (See Figure 2).

In conjunction with the development of the net economic value estimates for this 5-year program the minimum bid also has been analyzed and identified as a planning area specific policy tool to encourage efficient exploration and development. Appendix F presents the conceptual basis for using the minimum bid to accomplish these objectives.

Alternative bidding systems have currently not been addressed in terms of their effects on competition and fair market value. Based on past analysis of these systems the Department has found that the effects on competition have been negligible. (See: DOI, MMS: "Report to Congress on Fiscal Year 1983 Outer Continental Shelf Lease Sales and Evaluation of Alternative Bidding Systems", April 1983).



*The $150 per acre bonuses are actual bonuses received; $25 and $300 per acre aggregate bonuses are estimated.

Figure 2

VI. Conclusions

An objective of the offshore leasing program is to maximize the contribution to national income from leasing activities, including exploration, development, and production. It takes into consideration existent and projected market conditions affecting OCS oil and gas leasing rates. The Secretary's continuing assessment of the OCS lease market and the resultant policies and procedures developed for considering bid adequacy are also the measures used to assure the receipt of fair market value. These policies and procedures are not static and change in response to an assessment of the market conditions over time. The description of bid adequacy procedures in section V reflects an understanding of the lease market and procedures necessary to assure that fair market value is being received.

The Secretary, in formulating an OCS leasing schedule is also required to consider and balance other factors which are important to the Nation in the management of the resources of the OCS. Included are national security benefits, environmental costs and benefits, equitable sharing among regions, Government receipts, etc. Many of these factors cannot easily or necessarily be quantified but must be considered in the formulation of an oil and gas leasing program.

It is worth noting that the Secretary is not required to maximize any one of these elements, such as Government rereipts. The U.S. Court of Appeals for the District of Columbia in its decision on the 5-year leasing program in July 1983 states:

> Section 18(a)(4)'s requirement that the program assure receipt of fair market value does not mandate the maximization of revenues, it only requires receipt of a fair return.

The court thus distinguished between meeting the legal requirement and the broader policy question about distribution of benefits between lessees and the Government.

APPENDIX L

STEPS IN OFFSHORE LEASING FOR STANDARD SALES

STEPS IN OFFSHORE LEASING FOR STANDARD SALES

EARLY COORDINATION

Before the preparation of the Call for Information and Nominations, various contacts are made by Minerals Management Service (MMS) officials with the governments of affected coastal States. These contacts are tailored for each sale and can include the following: a letter to the Governor of each affected State announcing the commencement of the planning process, including a description of the steps in the prelease process with an indication of points at which the Governor's comments will be solicited, a commitment to provide specific time and locations of scoping meetings and draft EIS hearings as soon as possible, and a copy of the most recent planning schedule; letters or phone calls to appropriate State members of the Policy Committee and the Regional Technical Working Group (RTWG); and discussions concerning the potential Call area.

IDENTIFY AREA OF HYDROCARBON POTENTIAL

At least two months before the Call for Information and Nominations is published, the MMS determines the area of hydrocarbon potential (AHP) for the upcoming sale. This is the area considered by MMS to have potential for the discovery of oil and gas.

CALL FOR INFORMATION AND NOMINATIONS; NOTICE OF INTENT TO PREPARE AN EIS

The Call, signed by the Assistant Secretary - Land and Minerals Management (ASLM) and published in the Federal Register at month 1, invites potential bidders to nominate areas and indicate levels of interest in leasing and solicits comments from States and all interested parties on any environmental effects and use conflicts as well as coastal zone consistency concerns. States and others have the opportunity to comment on areas or topics of concern that should be considered in planning the lease sale. The Call also identifies the AHP. Comments are due 45 days after the Call is published. At this time in the leasing process, consultation is begun concerning possible multiple use conflicts with the Department of Defense (DOD) activities in the sale area. Also, information is provided to affected States under section 8(g) of the OCS Lands Act.

A Notice of Intent to prepare an Environmental Impact Statement (EIS) is also published. It announces the initiation of EIS scoping and invites public assistance in determining the significant issues, including coastal zone consistency issues, and alternatives to be analyzed in the EIS on the lease sale.

The Call and Notice of Intent are sent to the Governor of each affected State by the Regional Director with a letter which invites comments on the Call. In the letter, the Governor is asked to identify issues and areas of concern which should be considered in the development of the initial leasing proposal. The Regional Director's letter also indicates interest in meeting with representatives of the State to discuss the State's comments on the Call. Possible mitigating measures to accommodate concerns may be identified at this step. Conflicts which may arise during State consistency concurrence review of plans of exploration and development and production (per section 307(c)(3) of the Coastal Zone Management (CZM) Act) may also be identified at this meeting.

Letters and/or phone calls to appropriate Policy Committee and RTWG members and section 8(g) letters are also initiated at this time by the MMS regional office.

AREA IDENTIFICATION

About 4 months after the Call is published, after the analysis of nominations and comments, MMS recommends the area to be studied in an EIS as the proposed Federal action. When the ASLM approves this proposal it becomes the Area Identification. Areas may be deleted at this stage from further study where significant multiple use conflicts exist and the potential for hydrocarbon discovery is low. After any area identification is made, the MMS provides the affected States with more detailed information concerning section 8(g) blocks if appropriate. Consultation with a State over potential section 7 boundary issues may be initiated if appropriate.

Following the announcement of Area Identification, the Regional Director provides the Governor with an explanation of what was done with the State's comments--how the comments were employed in the Area Identification process and how they will be employed in the development of alternatives and mitigating measures to be analyzed in the EIS.

In addition to providing the Governor of each affected State with an explanation of how his recommendations were used in the decision process on Area Identification and how they will be used elsewhere in the prelease process, the letter invites additional comments from the State for use in the development of the EIS. These comments are folded into the scoping process.

DRAFT ENVIRONMENTAL IMPACT STATEMENT

About one year after the Call is published, a draft EIS is issued which describes the entire planning area and focuses on the potential environmental effects of oil and gas activities in the area proposed for leasing. The EIS includes evaluation of possible future Coastal Zone Management Act (CZMA) section 307(c)(3) conflicts. For sales in the Alaska Region, the EIS also evaluates the effects on subsistence uses that could occur from leasing, exploration, and development/production of OCS oil and gas, as required by court cases interpreting section 810 of the Alaska National Interest Lands Conservation Act (ANILCA). The document also analyzes alternatives to the proposed action. The availability of the draft EIS is announced in the Federal Register.

PUBLIC COMMENT PERIOD

A 60-day comment period follows public availability of the draft EIS, during which time public hearings are held in the affected region. Comments received either at public hearings or in writing are considered in preparation of the final EIS.

Public hearings on the draft EIS are announced by means of a letter from the MMS Regional Director to the Governor of each affected State as well as the Federal Register Notice. Copies of the letter to the Governor of each affected State are sent to the appropriate Policy Committee and RTWG members.

The MMS Regional Director transmits the draft EIS to the Governor of each affected State and solicits comments on the EIS as well as substantive comments on the proposal. The letter also invites the State to participate in a meeting to discuss the State's comments. Copies of the letter to the Governor are provided to the appropriate Policy Committee and RTWG members.

FINAL ENVIRONMENTAL IMPACT STATEMENT; PROPOSED NOTICE OF SALE

The final EIS is prepared, which assesses and considers comments received during the draft EIS public comment period. These include further State and local comments on coastal zone consistency matters and, for Alaska sales, subsistence uses. A Secretarial Issue Document (SID) is prepared to analyze all issues involved in the proposed sale, again including possible coastal zone consistency conflicts that could be expected at the exploration and development stages. The proposed Notice, signed by the ASLM and generally planned to be published shortly after the filing of the final EIS with the Environmental Protection Agency, contains the proposed terms and conditions of the sale. Blocks proposed for leasing, stipulations, and other mitigating measures are listed, along with proposed bidding systems and lease terms.

As required by section 19 of the OCS Lands Act, the proposed Notice is sent to Governors of affected States with a letter requesting comments on size, timing, or location of the sale. This letter also explains how State coastal zone management program policies have been considered in decisionmaking and invites any further comment the State wishes to make. A copy of this letter is sent to the States' official contact in the coastal zone management agency and to the appropriate Policy Committee members. If the proposed sale contains blocks that are within 3 miles of the Federal/State boundary, an offer of an agreement to equitably distribute revenues from these blocks under section 8(g) of the OCS Lands Act is also made to the affected States. If there is a litigated Federal/State jurisdictional dispute involving blocks proposed for leasing in a sale, an agreement offer is made to the State at this time under section 7 of the OCS Lands Act. By this time in the leasing process, the MMS and DOD have usually reached agreement on mitigating measures and deferrals to assure compatible mutual use of a sale area.

SUPPLEMENTAL NOTICES

Supplemental Notices highlighting specific questions on a proposed sale may also be published for public response at various points in the presale process.

GOVERNORS' COMMENTS

The Governors of affected States have 60 days in which to comment on size, timing, or location of the sale. These comments are used to develop recommendations to the Secretary regarding the final Notice.

FINAL NOTICE OF SALE

After comments are received from the Governors, a final decision memorandum which analyzes all issues is prepared for the Secretary. The Secretary is to accept recommendations of a Governor if the Secretary determines that they provide for a reasonable balance between the national interest and the well being of the affected State. The rationale for this determination is to be communicated to the Governor in writing. About 90 days after the proposed Notice is published and after consideration of comments from the Governors, the Secretary issues a final Notice of Sale, if he decides to proceed. The date, timing, location, blocks to be offered, terms, and conditions of the sale are published in the Federal Register not less than 30 days before the sale is conducted.

SALE

At least 30 days after the final Notice is published, a sale is conducted by the appropriate regional office. A public opening and reading of sealed bids submitted by qualified bidders occurs.

BID ADEQUACY REVIEW

High bids for each block are evaluated after the sale to assure receipt of fair market value. The Justice Department and Federal Trade Commission also review the results to insure that awarding leases does not create a situation inconsistent with antitrust laws.

LEASES ISSUED

The Secretary has up to 90 days after receipt of bids to either accept or reject a bid. Bid acceptance has been delegated to the MMS Regional Director; normally, bids are accepted and leases issued within 1-2 months after the sale.

APPENDIX M

FEDERAL REGISTER NOTICES ON THE DEVELOPMENT OF THE NEW 5-YEAR PROGRAM

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M-1 Extension of Period of Confidentiality for Privileged or Proprietary Data Submitted in Response to the Request for Comments on the Draft Proposed Program

M-2 Request for Comments on the Draft Proposed Program

M-11 Intent to Prepare an Environmental Impact Statement

M-12 Request for Comments on the Development of the 5-Year OCS Oil and Gas Leasing Program

M-17 Request for Comments on Appendix P

Extension of Period of Confidentiality for Privileged or Proprietary Data Submitted in Response to the Request for Comments on the Draft Proposed 5-Year Outer Continental Shelf (OCS) and Gas Leasing Program for Mid-1986 through Mid-1991.

SUMMARY: The Request for Comments on the Draft Proposed 5-Year OCS Oil and Gas Leasing Program for Mid-1986 through Mid-1991 was published in the **Federal Register** on March 22, 1985 (50 FR 11565).

In that Notice, it was stated that "Industry respondents in particular are requested to rank all planning areas of the OCS which now number 28 instead of 24. In order to encourage the frankest response, each respondent's ranking, upon request, will be deemed to be privileged or proprietary information to be treated as confidential for a period of 2 years after receipt by MMS (the Minerals Management Service). Confidential treatment of information is authorized under section 18(g) of the OCS Lands Act."

Section 18(g) of the OCS Lands Act does not specify any period for confidentiality. Two years was chosen so as to cover the period of development of the new program. Based upon preliminary response to the Request for Comments published in the **Federal Register**, it has been determined that the period for confidentiality should correspond to the period to be covered by the new program.

Consequently, upon request, individual rankings of planning areas will be treated as confidential privileged or proprietary data for a period of 5 years after final approval of the new 5-year program. Any other privileged or proprietary data submitted with comments on the Draft Proposed 5-Year Program will be treated as confidential for the period provided by the OCS Lands Act and regulations in Chapter II of Title 30 of the Code of Federal Regulations.

While each ranking attachment will be treated as confidential information for a period of 5 years after final approval of the new 5-year program, summaries of rankings prepared by MMS, the names of respondents submitting rankings, and comments other than rankings will not be treated as confidential information.

DATES: No comments are requested on this notice. Comments on the Draft Proposed 5-Year Program, as indicated in Notice published in the **Federal Register** on March 22, 1985, must be received by May 20, 1985.

ADDRESSES: Comments on the Draft Proposed 5-Year Program should be submitted to the Deputy Associate Director for Offshore Leasing, Minerals Management Service (MMS), Mail Stop 641, 12203 Sunrise Valley Drive, Reston, Virginia 22091. Hand deliveries to the Department of the Interior may be made to Room 2525, 18th & C Streets, NW., Washington, D.C. 20240. Envelopes or packages should be marked "Comments on the Draft Proposed 5-Year OCS Leasing Program." If any privileged or proprietary information which the respondent wishes to be treated as confidential is attached to comments, the envelope or package should be marked "Contain confidential information."

FOR FURTHER INFORMATION CONTACT: Telephone contact may be made with Chris Oynes, Chief, Offshore Leasing Management Division, MMS, at (202) 343-6906, or Paul Stang, Chief, Branch of Program Development and Planning, MMS, at (202) 343-1072.

Dated: May 10, 1985.

William D. Bettenberg,

Director, Minerals Management Service.

[FR Doc. 85-11747 Filed 5-13-85; 8:45 am]

BILLING CODE 4310-MR-M

Outer Continental Shelf Oil and Gas Leasing Program; Mid-1986 Through Mid-1991; Inquiry

AGENCY: Minerals Management Service, Interior.

ACTION: Request for Comments on the Draft Proposed 5-Year Outer Continental Shelf (OSC) Oil and Gas Leasing Program for Mid-1986 through Mid-1991.

SUMMARY: The Secretary of the Interior has just transmitted to the Governors of the affected coastal States and to the heads of affected Federal Agencies for review and comment the Draft Proposed 5-Year OCS Oil and Gas Leasing Program, prepared pursuant to section 18 of the OCS Lands act, as amended. That transmission is a formal but early step on the approximately 2-year process of analysis and consultation required for development of a new 5-year OSC oil and gas leasing program. The process was begun in July 1984 with letters to coastal State Governors and affected Federal Agencies and a **Federal Register** Notice (49 FR 28332, July 11, 1984) requesting initial comments and information on development of the new 5-year program. The Draft Proposed Program consists of a preliminary schedule of sales including presale milestones for the period July 1986 through June 1991 and a selection of leasing policies. These policies concern the configuration of OCS planning areas, the size of sales as determined by the presale process, and the means of assuring the receipt of fair market value for lands leased and rights conveyed. A Notice of intent to prepare an environmental impact statement (EIS) also appears in today's **Federal Register**. This Notice seeks public comments on the schedule and policies selected as the Draft Proposed Program. The responses to this Notice will be considered for the Secretarial decision on the adoption of a Proposed 5-Year OCS Oil and Gas Leasing Program planned for release in the summer of 1985. That release will be followed by a further 90-day comment period and further evaluation.

DATES: Comments must be received by May 20, 1985.

ADDRESSES: Comments should be submitted to the Deputy Associate Director for Offshore Leasing, Minerals Management Service (MMS), Mail Stop 641, 12203 Sunrise Valley Drive, Reston, Virginia 22091. Hand deliveries to the Department of the Interior may be made to Room 2525, 18th & C Streets NW., Washington, D.C. 20240. Envelopes or packages should be marked "Comments on the Draft Proposed 5-Year OCS

Leasing Program." If any privileged or proprietary information which the respondent wishes to be treated as confidential is attached to comments, the envelope or package should be marked "Contains confidential information."

FOR FURTHER INFORMATION CONTACT: Telephone contact may be made with Chris Oynes, Chief, Offshore Leasing Management Division, MMS, at (202) 343-6908, or Paul Stang, Chief, Branch of Program Development and Planning, MMS, at (202) 343-1072.

Author: Robert Samuels, Branch of Program Development and Planning, MMS.

SUPPLEMENTARY INFORMATION: The Department of the Interior (DOI) has developed the Draft Proposed Program within the framework of section 18 of the OCS Lands Act, as amended. Section 18 requires that the 5-year program be designed to meet national energy needs. Thus, one objective of the program is to allow all parties to plan for OCS leasing activities while providing sufficient flexibility to meet national energy needs.

Pursuant to section 18, the schedule and policies selected for the Draft Proposed Program were based on a consideration of a number of factors specified by the act and provide "to the maximum extent practicable, a proper balance between the potential for environmental damage, the potential for the discovery of oil and gas, and the potential for adverse impact on the coastal zone."

The preliminary decisions made for the Draft Proposed Program are described below. This is the first of several steps in the development of the new program. The proposals which comprise the Draft Proposed Program will be reviewed at the later program development stages: the Proposed Program, schedule for release in the summer of 1985; the Proposed Final Program, planned for the spring of 1986; and final approval. Secretarial approval of a final new 5-Year OSC Oil and Gas Leasing Program will follow appropriate consultation and a 60-day notification period before Congress.

Maps and a table showing the planning areas and their geographic boundaries appear at the end of this Notice along with Figure 1 which depicts the leasing schedule selected for the Draft Proposed Program.

1. Planning Area Boundaries for the Draft Proposed Program

In the July 1984 **Federal Register** Notice requesting comments on the development of the new program, 24 OCS planning areas were depicted. The Draft Proposed Program selection revises the July 1984 description by establishing outer boundaries for planning areas and reconfiguring the OCS into 28 planning areas.

This reconfiguration has two parts: the division of the South Atlantic into two areas (South Atlantic and Straits of Florida) to allow a more concentrated review of those areas under the provisions of section 18; and the reconfiguration of planning areas offshore California from two to three to allow a more concentrated section 18 review of those areas as well as to respond to public comments.

The key factor in the reconfiguration of the areas offshore California is that there are discoveries in the basin on both the south and west sides of Santa Barbara County. It will thus be better for planning and administrative purposes to treat them together for the scheduling of lease sales and analyzing in a single EIS potential impacts on air quality, transportation of oil and gas, and other environmental factors. The other four basins offshore California are divided equally, i.e., two and two, to form the new Central and new Northern California planning areas.

In addition to the above reconfiguration of planning areas, outer boundaries have been selected. The outer boundaries of the Washington-Oregon and Northern California areas are being set at 128° W. longitude so as to encompass the area of hydrocarbon potential in those regions. In the Beaufort Sea, Official Protraction Diagram NS 7-6 is being added so as to include that area for consideration for leasing in the new program.

2. The Leasing Schedule for the Draft Proposed Program

Over the period mid-1986 through mid-1991, the Draft Proposed Program provides for 33 standard sales, 5 frontier exploration sales, and 5 supplemental sales.

This contrasts with the current program (as approved in July 1982), which provided for 40 standard sales and 1 reoffering sale. The new draft schedule proposes the continuation of annual sales in the two highest-value, highest-interest areas: the Central and Western Gulf of Mexico. It proposes triennial sales in 15 other areas. This triennial pacing of sales contrasts with the biennial pace in the current 5-year program. Other features of the proposed schedule are described below.

The first OCS sale in 27 years is proposed for 1991 offshore Washington and Oregon given the value of that area's resources and industry interest. The schedule also proposes the first sale in Hope Basin, offshore Alaska, also in 1991. The sales for these areas are proposed late in the 5-year period to allow time for the necessary environmental studies to be performed.

a. The Base Schedule

The base schedule proposes 33 standard sales in 17 planning areas. The 11 sales numbered in Figure 1 are sales carried over from the current to the new program.

b. Frontier Exploration Sales Offshore Alaska

Five frontier exploration sales have been proposed offshore Alaska to increase the flexibility of the schedule to respond to changes in prices and other economic conditions or improved geologic and geophysical data. These five sales are proposed for the Gulf of Alaska (1988), Cook Inlet (1989), Shumagin (1990), Hope Basin (1991), and Kodiak (1991). The 1987 Shumagin sale, Sale 88, is carried over from the current schedule as a standard sale. In these frontier areas, the assessment of oil and gas resources is incomplete, and at this time, industry interest appears low.

These frontier exploration sales will include an additional presale step: a Request for Interest scheduled for 4 months prior to the Call for Information and Nominations. Responses to each Request will be used to help determine whether the approximately 2-year sale process should proceed in those areas. The annual review of the program under section 18(e) will also be used to determine whether to proceed with these sales.

c. Supplemental Sales

The schedule also includes an annual sale for a limited number of selected blocks in areas other than the Central and Western Gulf of Mexico: drainage and development blocks; and blocks on which bids were rejected in the preceding calendar year. These sales will provide for: (1) The expeditious offering of blocks in which serious industry interest can reasonably be anticipated; (2) orderly development of OCS resources (increasing the potential for actual development and reducing the time necessary to bring new fields into production); and (3) minimization of costs of delay. These blocks will only be offered after compliance with the requirements of the National Environmental Policy Act, the OCS Lands act, and other applicable statutes. The environmental assessment documentation for each of these sales would be released at approximately the same time as the Proposed Notice of Sale. If it is determined that an EIS is required for one of these sales, revised presale milestones will be issued.

d. Areas in Which no Sales Are Proposed in the Draft Proposed Program

The schedule proposes no sales in St. Matthew-Hall, Aleutian Arc, Aleutian Basin, and Bowers Basin so as to concentrate management resources on other areas with higher resource potential and industry interest. Comments are requested on this part of the proposal in the final section of this Notice. No sale has been scheduled for the Straits of Florida since this area has not yet been analyzed as a separate planning area. Section 18 analysis of and comments on the Straits of Florida as a new planning area will be available for the decision on the Proposed Program.

e. Flexibility Provision

The DOI must plan for an unknown future with limited information. Changes in the world energy market as well as exploration results in frontier areas can dramatically affect the demand for offshore leases. The statutory requirement to develop "a schedule of proposed lease sales indicating, as precisely as possible, the size, timing, and location of leasing which [the Secretary] determines will best meet national energy needs for the 5-year period following its approval . . ." must be applied with due recognition that what will be known tomorrow may well be very different from what is known today.

To comply fully with the statutory requirement to meet national energy needs over the 5 years of the program, the schedule should have the flexibility to respond to changing conditions. Thus, the new program includes a provision to accelerate sales in areas of higher value and/or higher interest (but not so as to increase the total number of sales in any planning area in the approved program). The areas where such acceleration would be considered include: Southern California; Eastern Gulf of Mexico; Central California; Northern California; Navarin Basin; Beaufort Sea; North Aleutian Basin; and St. George Basin. Specific guidelines for the implementation of the acceleration provision will be developed for the Proposed Program and available for public comment before final approval of the program.

Such a provision would be used only if warranted by changes in economic conditions (for example, substantially higher oil price expectations such as might result from a serious oil supply disruption) or geologic data (such as could come from major new discoveries). The question of whether to accelerate a sale in an area would be made on a sale-by-sale basis, as part of the required annual review of the program under section 18(e). No new sales would be added to the program in any planning area under this provision.

4. Size of Lease Sales

It is proposed that the size of lease sales be determined by a presale process which results in the offering of promising acreage. Promising acreage is that which is reasonably determined to be likely to lead to exploration and/or development of oil and gas resources. That determination will be made by means of a consultative process which will provide for the early resolution of conflicts based on information and nominations obtained from affected Federal Agencies, State and local governments, the public, and potential bidders, as well as Minerals Management Service analysis.

The offering of promising acreage will give effect to DOI's desire to make available for lease areas of hydrocarbon potential as identified by industry and MMS, while remaining cognizant of the particular circumstances relevant to each sale. The various OCS areas and the adjacent onshore regions vary significantly in terms of exploration and development history, onshore support capability, and possible multiple-use conflicts. In preparing for leasing activity, regional differences will be taken into account on a case-by-case, sale-by-sale basis, and the emphasis will be on consultation, and, wherever possible, consensus.

5. Assurance of Receipt of Fair Market Value in the Draft Proposed Program

Section 18(a)(4) provides that leasing activities are to be conducted so as to assure receipt of fair market value for lands leased and rights conveyed. The policy option selected for the Draft Proposed Program maintains current procedures for assuring the receipt of fair market value. In 1984, a number of adjustments were made to improve fair market value procedures based upon evaluations of these procedures conducted by MMS independent of the formulation of the new leasing program. The policy option selected also provides for a review under the auspices of the development of the new 5-year program of the question of whether the minimum bid level should be changed either in general or on a variable basis for different planning areas.

Information requested

This Notice has been prepared to obtain public views on the above proposals. Comments may be submitted on any topic related to the new 5-year program.

Comments are requested on the following specific topics:

(1) The proposed configuration of planning area boundaries.

(2) The appropriateness of the number of proposed sales and the interval between proposed sales.

(3) The appropriateness of the location of proposed sales.

(4) The proposed presale process.

(5) The proposed means of pursuing flexibility in the new program in light of uncertainty over future oil and gas prices and national energy needs.

(6) Whether considerations such as the following concerning the level of the minimum bid would warrant varying the current minimum bid level of $150 per acre on a nationwide or planning area basis: (1) Changes in economic conditions such as oil prices; or (2) potential effects on the number of tracts leased or the rate of exploration and development.

(7) Whether the tract size limit of 5,760 acres ought to be expanded; and whether enlargement of the maximum tract size is an alternative which would achieve effects comparable to varying the minimum bid. Under section 6(b)(1) of the OCS Lands Act, the Secretary of the Interior has the authority to enlarge the maximum tract size if necessary to comprise a reasonable economic production unit.

(8) Whether there are subareas within planning areas which should be subject to special considerations, either in the presale planning process for each sale or, more generally, within the 5-year program itself, and what those considerations should be.

Industry respondents in particular are requested to rank all planning areas of the OCS which now number 28 instead of 24. In order to encourage the frankest response, each respondent's ranking, upon request, will be deemed to be privileged or proprietary information to be treated as confidential for a period of 2 years after receipt by MMS. Confidential treatment of information is authorized under section 18(g) of the OCS Lands Act. In order that only rankings be treated as confidential, they should be submitted as an attachment to the other comments a respondent submits. While each ranking attachment will be treated as confidential information for a period of 2 years, statistical summaries of rankings

prepared by MMS, the names of respondents submitting rankings, and comments other than rankings will not be treated as confidential information.

Separate rankings are requested for: (i) Hydrocarbon potential; and (ii) exploration and development interest. Both rankings should be based on estimates of resources expected to be undiscovered as of mid-1988. Industry respondents are also asked to indicate those areas in which they have intentions to operate or serious interest in operating so that their rankings can be interpreted most usefully by MMS.

The following maps and Table 1 depict and describe the planning area boundaries selected as part of the Draft Proposed Program. Figure 1 depicts the leasing schedule selected for the Draft Proposed Program.

Dated: March 19, 1985.

William D. Bettenberg,

Director, Minerals Management Service

BILLING CODE 4310-MR-M

U.S. Department of the Interior
Minerals Management Service

Figure 1
DRAFT PROPOSED PROGRAM
MARCH 1985

SALE	AREA	PROPOSED DATE	1985 J F M A M J J A S O N D	1986 J F M A M J J A S O N D	1987 J F M A M J J A S O N D	1988 J F M A M J J A S O N D	1989 J F M A M J J A S O N D	1990 J F M A M J J A S O N D	1991 J F M A M J
105	N. Gulf of Mexico Supplemental 1	7/86	EH F	P G NS					
107	Navarin Basin	9/86	EH	P GNS					
97	Beaufort Sea	12/86	A EH	FP GNS					
95	S. California	4/87	C A	EH FP GNS					
110	C. Gulf of Mexico	4/87	C A	EH F P GNS					
109	Chukchi Sea	5/87	A C	EH F P GNS					
	W. Gulf of Mexico Supplemental 2	8/87	C A	EH F P GNS					
96	N. Atlantic	11/87	C A	EH FP GNS					
86	Shumagin	12/87	C A	EH FP GNS					
91	N. California	12/87	C A	EH FP GNS					
	C. Gulf of Mexico	2/88	C A	EH FP GNS					
	Gulf of Alaska	3/88	C A	EH F P GNS					
	E. Gulf of Mexico	3/88	C A	EH F FP GNS					
101	St. George Basin	5/88	C A	EH F P GNS					
	W. Gulf of Mexico Supplemental 3	8/88	C A	EH F P GNS					
	Mid-Atlantic	6/88	C A	EH FP GNS					
	N. Aleutian Basin	10/88	C A	EH FP GNS					
	C. Gulf of Mexico	12/88	C A	EH FP GNS					
	Norton Basin	2/89	C A	EH F P GNS					
	C. California	3/89	C A	EH F FP GNS					
116	S. Atlantic	5/89	C A	EH F P GNS					
	W. Gulf of Mexico Supplemental 4	7/89	C A	EH F P GNS					
	Navarin Basin	8/89	C A	EH FP GNS					
	Beaufort Sea	6/89	C A	EH FP GNS					
	E. Gulf of Mexico	12/89	C A	EH FP GNS					
	Chukchi Sea	2/90	C A	EH FP GNS					
	S. California	3/90	C A	EH FP GNS					
	Cook Inlet	4/90	R C A	EH F F GNS					
	W. Gulf of Mexico Supplemental 5	6/90	R C A	EH F F GNS					
	Shumagin	8/90	R C A	EH FP GNS					
	N. Atlantic	9/90	C A	EH FP GNS					
	N. California	10/90	C A	EH FP GNS					
	Kodiak	12/90	R C A	EH FP GNS					
	C. Gulf of Mexico	1/91	C A	EH FP GNS					
	St. George Basin	2/91	C A	EH FP GNS					
	Washington-Oregon	4/91	C A	EH FP GNS					
	E. Gulf of Mexico	4/91	C A	EH F P GNS					
	Hope Basin	5/91	R C A	EH EP FP GNS					

R - Request for Interest C - Call for Information & Nominations A - Area Identification
E - Draft EIS M - Public Hearing F - Final EIS P - Proposed Notice of Sale
G - Governor's Comments Due N - Notice of Sale S - Sale

Map 2

OUTER CONTINENTAL SHELF
PLANNING AREAS
U.S. DEPARTMENT OF THE INTERIOR
MINERALS MANAGEMENT SERVICE
BEAUFORT SEA
CHUKCHI SEA
HOPE BASIN
NORTON BASIN
ST. MATTHEW HALL BASIN
NAVARIN BASIN
ALEUTIAN BASIN
BOWERS BASIN
ST. GEORGE BASIN
NORTH ALEUTIAN BASIN
COOK INLET
GULF OF ALASKA
KODIAK
SHUMAGIN
ALEUTIAN ARC
ALASKA
CANADA
U.S.A.

Map 1

OUTER CONTINENTAL SHELF PLANNING AREAS
U.S. DEPARTMENT OF THE INTERIOR
MINERALS MANAGEMENT SERVICE
GULF OF MEXICO
STRAITS OF FLORIDA
WESTERN
CENTRAL
EASTERN
S. ATLANTIC
MID-ATLANTIC
S. CALIFORNIA
C. CALIFORNIA
N. CALIFORNIA
WASHINGTON
OREGON

Table 1—Description of Planning Areas

1. North Atlantic: Extends south from the juncture of the territorial sea at 71° W longitude to 39° N latitude thence east to the juncture of an extension of the U.S.-Canada Maritime Boundary thence north along that extension to the territorial sea thence following the territorial sea to the point of origin.

2. Mid-Atlantic: Extends east from the juncture of the territorial sea at approximately 35° N latitude to 70° W longitude thence north to approximately 37° N latitude thence east to 68° W longitude thence north to approximately 38° N latitude thence east to 66° W longitude thence north to 71° W longitude thence north to the territorial sea thence along the territorial sea to the point of origin.

3. South Atlantic: East from the juncture of the territorial sea at approximately 35° N latitude to 70° W longitude thence south to 34° N latitude thence west to 72° W longitude thence south to 32° N latitude thence west to 74° W longitude, thence south to 31° N latitude thence west to 78° W longitude thence south to 28°17' N latitude thence west to the territorial sea limits thence north along the territorial sea to the point of origin.

4. Straits of Florida: East from the juncture of the territorial sea at 28°17' N latitude to 78° W longitude thence south to the limits of U.S. jurisdiction thence southwest along the line of U.S. jurisdiction to approximately 81°13' W longitude at 23°58' N latitude thence west to 82° W longitude thence north to the territorial sea abutting the Dry Tortugas thence east to the limits of the territorial sea thence along the territorial sea to the point of origin.

5. Eastern Gulf of Mexico: South from the territorial sea at approximately 87°48' W longitude to approximately 29° N latitude thence west to approximately 87°58' W longitude thence south to approximately 28° N latitude thence east to approximately 85°56' W longitude thence south to the limit of U.S. jurisdiction thence southeast to approximately 83°55' W longitude at approximately 24° N latitude thence east to 83° W longitude thence to the limits of the territorial sea thence east to approximately 82°25' W longitude thence north and east along the territorial sea to the limits of U.S. jurisdiction thence along the territorial sea to the point of origin.

6. Central Gulf of Mexico: South from the territorial sea at approximately 87°48' W longitude to approximately 29° N latitude thence west to approximately 87°58' W longitude thence south to approximately 28° N latitude thence west to approximately 91°56' W longitude, except that between approximately 88°23' W longitude and 91°05' W longitude the boundary is the U.S.-Mexico Provisional Maritime Boundary, thence north to approximately 27°58' N latitude thence generally west to approximately 93°25' W longitude thence northwest to the juncture of the territorial sea at approximately 93°30' W longitude thence east along the territorial sea to the point of origin.

7. Western Gulf of Mexico: East from the territorial sea along the U.S.-Mexico Provisional Maritime Boundary to approximately 25°45' N latitude thence along approximately 28° N latitude to approximately 91°55' W longitude thence north to approximately 27°55' N latitude thence generally west to approximately 93°25' W longitude thence northwest to the juncture of the territorial sea at approximately 93°30' W longitude thence along the territorial sea to the point of origin.

8. Southern California: West along a line extending from the territorial sea at approximately 35°47' N latitude to approximately 124° W longitude thence south to approximately 34°58' N latitude thence east to approximately 122° W longitude thence south to approximately 32°56' N latitude thence east to approximately 121°40' W longitude thence south to approximately 32°40' N latitude thence east to approximately 120°20' W longitude thence south to approximately 32°16' N latitude thence east to 120° W longitude thence south to the U.S.-Mexico Provisional Maritime Boundary thence along the U.S.-Mexico Provisional Maritime Boundary to the territorial sea thence along the territorial sea to the point of origin.

9. Central California: West along a line extending from the territorial sea at approximately 35°47' N latitude to approximately 124° W longitude thence north to approximately 37°50' N latitude thence west to approximately 125° W longitude thence north to approximately 38°46' N latitude thence east to the territorial sea thence along the territorial sea to the point of origin.

10. Northern California: West along a line extending from the territorial sea at approximately 38°46' N latitude to approximately 128° W longitude thence north to approximately 42° N latitude thence thence east to the territorial sea thence along the territorial sea to the point of origin.

11. Washington-Oregon: West along a line extending from the territorial sea at approximately 42° N latitude to 128° W longitude thence north to the limits of U.S. jurisdiction thence east to the territorial sea thence along the territorial sea to the point of origin.

12. Beaufort Sea: West from the juncture of U.S. jurisdiction at 73° N latitude to 162° W longitude thence south to 71° N latitude thence east to the limits of the territorial sea thence east to the limit of U.S. jurisdiction thence north to the point of origin.

13. Chukchi Sea: East from approximately 166° W longitude at 73° N latitude to 162° W longitude thence south to 71° N latitude thence east to the limits of the territorial sea thence generally southwest to approximately 66°20' N latitude at 167° W longitude thence west to the U.S.-Russia Convention Line thence north to the point of origin.

14. Hope Basin: Extends west from the juncture of the territorial sea at 66°20' N latitude to the U.S.-Russia Convention Line thence south along the U.S.-Russia Convention Line to 65°25' N latitude thence east to the limits of the territorial sea thence along the territorial sea to the point of origin.

15. Norton Basin: Extending west from the juncture of 65°35' N latitude at 168°15' W longitude to the U.S.-Russia Convention Line thence generally southwest along that line to approximately 63° N latitude at 175° W latitude thence east to the territorial sea thence along the territorial sea to the point of origin.

16. Navarin Basin: Extends southwest from the juncture of approximately 63° N latitude at the U.S.-Russia Convention Line along that line to 180° longitude thence south to approximately 58° N latitude thence east to 174° W longitude thence north to approximately 63° N latitude thence west to the point of origin.

17. St. Matthew-Hall: West from the territorial sea at approximately 63° N latitude at 168° W longitude to 174° W longitude thence south to approximately 59° N latitude thence east to the territorial sea thence following the territorial sea to the point of origin.

18. St. George Basin: South from 59° N latitude at 174° W longitude to 56° N latitude thence east to 171° W longitude thence south to approximately 52°35' N latitude thence east to the limits of the territorial sea thence following the territorial sea east to approximately 170°30' W longitude at 52°40' N latitude thence east to the limit of the territorial sea at approximately 52°40' N latitude thence following the territorial sea to approximately 52°40' N latitude thence east to the limit of the territorial sea thence northeast to 166° W longitude thence north to 59° N latitude thence west to the point of origin.

19. North Aleutian Basin: West from 161°52' W longitude at approximately 59° N latitude to 166° W longitude thence south to the intersection with the territorial sea thence following the territorial sea to the point of origin.

20. Shumagin: Extends south from a point at approximately 54°30' N latitude and 165° W longitude to 50° N latitude thence east to 156° W longitude thence north to 51° N latitude thence east to 154° W longitude thence north to 57° N latitude thence west to the territorial sea thence southwest along the territorial sea to the point of origin.

21. Cook Inlet: Extends east from approximately 56°57' N latitude at 156°25' W longitude to the intersection with the territorial sea thence generally northeast along the territorial sea to approximately 152°27' W longitude thence north to the territorial sea thence around the territorial sea to approximately 59° N latitude at 152° W longitude thence north to the territorial sea thence following the territorial sea to the point of origin.

22. Kodiak: Extends east from 57° N latitude at 156° W longitude to the territorial sea thence generally northeast along the territorial sea to approximately 152°27' W longitude thence north to the territorial sea thence around the territorial sea to approximately 59° N latitude thence east to 146° W longitude thence south to 56° N latitude thence east to 147° W longitude thence south to 53° N latitude thence west to 156° W longitude thence south to 52° N latitude thence west to 158° W longitude thence north to the point of origin.

23. Gulf of Alaska: Extends south from approximately 151°55' W longitude at 56°05' N latitude to the territorial sea at approximately 59° N latitude thence east to 146° W longitude thence south to 56° N latitude thence east to 147° W longitude thence south to 53° N latitude thence east to 141° W longitude thence generally northeast along the fishery conservation line to the territorial sea thence along the territorial sea to the point of origin.

24. Aleutian Basin: East from the juncture of approximately 56° N latitude at the U.S.-Russia Convention Line to 174° W longitude thence north to approximately 58° N latitude thence west to 166° longitude thence north to the juncture of the U.S.-Russia convention line thence along that line to the point of origin.

25. Bowers Basin: East from the juncture of approximately 56° N latitude at the U.S. Russia Convention line to 171° W longitude thence south to approximately 53° N latitude thence west to 174° E longitude thence north to approximately 54° N latitude thence west to the U.S.-Russia Convention Line thence along that line to the point of origin.

26. Aleutian Arc: East from the juncture of the U.S.-Russia Convention Line at approximately 54° N latitude to 174° E longitude thence south to approximately 53° N latitude thence east to 171° W longitude thence south to approximately 52°35' N latitude thence east to the limits of the territorial sea thence following the territorial sea east to approximately 170°30' W longitude at 52°40' N latitude thence east to the limit of the territorial sea at approximately 52°40' N latitude thence following the territorial sea to approximately 52°40' N latitude thence east to the limit of the territorial sea thence northeast to 166° W longitude thence south to approximately 50° N latitude thence west to approximately 167° E longitude thence north to the U.S.-Russia Convention Line thence along that line to the point of origin.

[BILLING CODE 4310-MA-M]

Intent To Prepare an Environmental Impact Statement for the Proposed 5-Year Outer Continental Shelf Oil and Gas Leasing Program for 1986-1990 Through 1991-1995

Pursuant to section 102(2)(C) of the National Environmental Policy Act of 1969, the Department of the Interior's Minerals Management Service (MMS) intends to prepare an environmental impact statement (EIS) regarding a proposed new 5-Year Outer Continental Shelf (OCS) oil and gas leasing program covering the period mid-1986 to mid-1991. The draft EIS is currently scheduled for release in the summer of 1985.

In July 1984, the Department of the Interior requested suggestions and information from the Governors of the affected coastal states, affected Federal Agencies, industry, and the public on the development of a new 5-year leasing program. Information was requested on the characteristics of the OCS planning areas, environmental sensitivity, technological feasibility of exploring and developing certain areas, and the ranking of OCS areas both by oil and gas potential and by interest in exploration and development.

The Secretary of the Interior has just transmitted to the Governors of the affected coastal States and the heads of affected Federal Agencies, for review and comment, the Draft Proposed 5-Year OCS Oil and Gas Leasing Program, prepared pursuant to section 18 of the OCS Lands Act, as amended. That transmission is a formal but early step in the approximately 2-year process of analysis and consultation required for development of a new 5-year OCS oil and gas leasing program. A Notice requesting comments on the Draft Proposed Program also appears in today's Federal Register.

Pursuant to 40 CFR 1501.7, this Notice initiates the scoping process for the EIS. The Department of the Interior hereby solicits information from Federal, State, and local agencies, and the public regarding alternatives and the issues which should be evaluated in the EIS. Respondents are requested to focus their comments on the environmental issues attendant to the proposal as defined in the Draft Proposed Program which appears elsewhere in today's Federal Register, and on alternative leasing schedules and presale processes which should be evaluated in the EIS.

DATES: Scoping comments should be received by May 20, 1985.

ADDRESS: Scoping comments should be submitted to Daniel Henry, Minerals Management Service, Mail Stop 644, 12203 Sunrise Valley Drive, Reston, Virginia 22091. Hand deliveries to the Department of the Interior may be made to Room 2510, 18th & C Streets, N.W., Washington, D.C. 20240. Envelopes or packages should be marked "Scoping Comments on the Proposed 5-Year Leasing Program EIS."

FOR FURTHER INFORMATION CONTACT: Daniel Henry, Branch of Environmental Evaluation, MMS, at (202) 343-6294.

Author: Daniel Henry, Branch of Environmental Evaluation, MMS.

Dated: March 19, 1985.

William D. Bettenberg,

Director, Minerals Management Service.

[FR Doc. 85-6910 Filed 3-21-85; 8:45 am]

BILLING CODE 4310-MR-M

5-Year Outer Continental Shelf Oil and Gas Leasing Program; Development and Request for Comments

AGENCY: Minerals Management Service, Interior.

ACTION: Notice of request for comments on the development of a new 5-year Outer Continental Shelf (OCS) Oil and Gas Leasing Program.

SUMMARY: Section 18 of the OCS Lands Act, as amended, requires the Secretary of the Interior to solicit suggestions from Federal Agencies, coastal States, and others during the preparation of a new 5-Year OCS Oil and Gas Leasing Program. The current leasing program, approved in July 1982, schedules lease sales through mid-1987. The Minerals Management Service intends to prepare a program for the period mid-1986 to mid-1991.

DATES: Comments and information must be received by August 27, 1984.

ADDRESS: Comments and information should be mailed to Deputy Associate Director for Offshore Leasing, Minerals Management Service (MS-641), 12203 Sunrise Valley Drive, Reston, Virginia 22091. Hand deliveries to the Department of the Interior may be made at 18th & C Streets NW., Room 2509, Washington, DC. Envelopes or packages should be marked "Comments on the 5-Year OCS Oil and Gas Leasing Program."

FOR FURTHER INFORMATION CONTACT: Telephone contact may be made with Paul R. Stang, (202) 343-1072, for information on the development of a new 5-Year leasing program.

Author

William J. Quinn, Offshore Leasing Management Division, Minerals Management Service, 12203 Sunrise Valley Drive, Reston, Virginia 22091.

SUPPLEMENTARY INFORMATION: Comments are requested from States, local governments, the oil and gas industry, Federal Agencies, and other interested individuals and groups to assist the Department of the Interior in the preparation of a 5-Year OCS Oil and Gas Leasing Program to cover the period mid-1986 to mid-1991. The program preparation effort now underway is expected to take about 2 years to complete. Approval of the new program in mid-1986 will help provide a smooth transition from the current to the new schedule.

The OCS leasing program schedule enables the Federal Government, affected States, industry, and other interested parties to plan for the steps leading to the offshore lease sales. A decision on whether to proceed with a specific sale on the schedule will be made only after all the applicable requirements of the OCS Lands Act (hereafter called the Act), National Environmental Policy Act (NEPA) of 1969, and other statutes have been met.

The program preparation process will follow all the procedural steps set out in section 18 of the Act. The purpose of this Notice is to solicit comments early in the program preparation process pursuant to section 18(c)(1) of the Act.

Your comments will be considered in the analysis required by section 18(a) of the Act. Once this analysis is completed, alternatives to the proposal will be developed which will include a range of schedules varying the timing or location of proposed offshore lease sales.

A draft proposed program will be prepared based on the section 18(a) analysis. The draft proposed program will display planning milestones and will refer to sales by name and number. Respondents should be aware that the following concepts will be considered in its development:

1. Both quantitative and qualitative information will be considered in meeting the requirements of section 18(a) of the Act;

2. Leasing activities under the program should assure receipt of fair market value for the lands leased (this is a statutory requirement of section 18(a)(4) of the Act);

3. A more flexible approach to leasing decisions will be considered for those planning areas in which the demand for additional leasing in the 1986-1991 period is expected to be limited but could be substantially increased by unexpected events.

The list of planning areas with boundaries described in Table 1 is open to comment. These areas will be subject to analysis under section 18 and will be considered as candidates for the draft proposed program. There are 18 such planning areas which are described in the current 5-year leasing schedule. Note also that the list includes planning areas which do not appear on the approved current schedule. These are: Hope Basin, St. Matthew-Hall, Aleutian Basin, Bowers Basin, Aleutian Arc, and Washington-Oregon. Note that the names of Diapir Field and Barrow Arch have been changed to Beaufort Sea and Chukchi Sea, respectively.

Precise marine boundaries between the United States and opposite or adjacent nations have not been determined in all cases. The maritime boundaries and limits depicted in Table 1 and the attached maps, as well as divisions between planning areas where shown, are for initial planning purposes only. These limits shall not affect or prejudice in any manner the position of the United States with respect to the nature or extent of the internal waters, of the territorial sea, of the high seas, or of sovereign rights or jurisdiction for any purpose whatsoever.

Information Requested

Comments are solicited as follows:

Information and comments submitted at this stage should be general or conceptual in nature and relevant to determining the appropriate overall size, timing, and location of sales to be considered in the leasing schedule. Data and information which support these general views are also requested. As required by section 18(c)(1) of the Act, any suggestions from the executive of any affected local government in an affected State shall be first submitted to the Governor of such State.

A. As noted above, the Secretary is required by section 18(a) of the Act to consider a number of factors in formulating a 5-year leasing program. We would like to have information and your suggestions relevant to the requirements of section 18(a). The following list provides an indication of the kind of information which would be most useful in conducting the section 18(a) analysis. Please note that not all factors may be relevant to all wishing to comment.

(1) Information on the economic, social, and environmental values of the renewable and nonrenewable resources contained in the OCS and the potential impact of oil and gas exploration on other resource values of the OCS and the marine, coastal, and human environments.

(2) Existing information concerning geographical, geological, and ecological characteristics of the regions of the OCS and nearshore evironments.

(3) Suggested methods and information for analyzing the sharing of developmental benefits and environmental risks among the various regions (planning areas) and ways to determine what constitutes an equitable sharing.

(4) Other uses of the sea and seabed, including fisheries, navigation, existing

or proposed sealanes, potential sites of deepwater ports, and other anticipated uses of the resources and space of the OCS.

(5) Methods and information for assessing relative environmental sensitivity and marine productivity of the different planning areas of the OCS.

(6) Relevant environmental and predictive information pertinent to offshore and coastal areas potentially affected by OCS developement.

(7) The location of planning areas with respect to, and the relative needs of, regional and national energy markets.

We would also like to have information on the availability of transportation networks to bring oil and gas supplies to demand areas, both on a current and projected basis.

B. Industry respondents are asked to address the following information needs in some detail. It should be emphasized that this information will be used to identify areas of potential for oil and gas development. When weighed against comments on possible environmental effects and the results of various environmental and other cost analyses, these expressions of interest play an important role in the section 18 balancing which ultimately determines the size, timing, and location of sales included in the 5-year program.

The following information is requested with respect to the OCS planning areas:

(1) Ranking of planning areas by order of oil and gas potential. To allow comparisons of responses in a consistent format, we ask that a single list be submitted showing areas ranked 1 through 24;

(2) Ranking of planning areas by order of interest in exploration and development, including reasons for any possible differences in this ranking compared to that in item (1); and

(3) Technological feasibility of conducting exploration and development within specified time periods for each planning area or, if appropriate, for specified portions of each planning area.

C. Suggestions are requested for possible revisions in the planning area boundaries described earlier in this Notice, with reasons for any such revisions.

D. Our information and knowledge of the oil and gas resources of the OCS will be more advanced in 1988 compared to 1982 when the current 5-year program was approved. We believe it may be appropriate to examine ways to help assure that we can accommodate this additional information when the new program begins and adjust the program as further knowledge of the OCS resources and national energy needs evolves. Hence, suggestions are also requested for changes in the leasing process which will allow for a more flexible program while still identifying location and timing as precisely as possible for planning purposes.

Dated: June 14, 1984.

Wm. D. Bettenberg,

Director, Minerals Management Service.

Dated: July 5, 1984.

Approved:

William Clark,

Secretary.

Table 1—Description of Planning Areas

1. *North Atlantic:* Lies offshore of the New England States and is bounded on the west by 71° W. longitude and on the south by approximately 36° N latitude.

2. *Mid-Atlantic:* Extends north from approximately 35° N. latitude along the coast to the intersection of 71° W. longitude thence south along 71° W. longitude to approximately 29° N. latitude, thence east along the 29th parallel.

3. *South Atlantic:* Lies offshore of the States of North Carolina, South Carolina, Georgia, and Florida and is bounded on the north by approximately 35° N. latitude.

4. *Eastern Gulf of Mexico:* Lies offshore of Florida and is bounded on the west by approximately 86° W. longitude and on the north and east by Florida.

5. *Central Gulf of Mexico:* Lies south of Louisiana, Mississippi, and Alabama and is bounded on the east by approximately 86° W. longitude. Its western boundary begins at the offshore boundary between Texas and Louisiana and proceeds southeasterly to approximately 28° N. latitude and 93° 30' W. longitude, thence east to approximately 82° W. longitude, and thence south.

6. *Western Gulf of Mexico:* Lies south and east of Texas. It is bounded on the east by the extension of the boundary between Texas and Louisiana and proceeds southeasterly to approximately 28° N. latitude and 93° 30' W. longitude, thence east to approximately 92° W. longitude, and thence south.

7. *Southern California.* Bounded on the north by approximately 34° 30' N. latitude and on the south by the U.S.-Mexico provisional boundary.

8. *Central and Northern California:* Bounded on the south by approximately 34° 30' N. latitude and on the north by approximately 42° N. latitude.

9. *Washington-Oregon:* Lies offshore of these two States and is bounded on the south by approximately 42° N. latitude and on the north by approximately 46° 30' N. latitude.

10. *Gulf of Alaska:* It is bounded approximately on the west by 151° 55' W. longitude, thence east along 59° N. latitude to 148° W. longitude, thence south to 58° N. latitude, thence east along 58° N. latitude to 147° W. longitude, thence south.

11. *Kodiak:* Lies generally southeast of Kodiak Island. It is bounded on the west by 156° W. longitude. From 156° W. longitude, it extends east along 57° N. latitude, thence northeast to 56° N. latitude, thence to 146° W. longitude, thence south to 56° N. latitude, thence east to 147° W. longitude, thence south.

12. *Cook Inlet:* Lies east of 156° W. longitude and north of 57° N. latitude to the Federal/State boundary south of Kalgin Island.

13. *Shumagin:* Lies southeast of the Alaskan Peninsula. It is bounded on the west by 165° W. longitude, on the east by 156° W. longitude, and on the north by 57° N. latitude.

14. *Aleutian Arc:* Bounded on the east by 165° W. longitude south of the Aleutian Islands chain, 171° W. longitude north of the Aleutian Islands chain, and on the north by 53° N. latitude thence west to 174° E. longitude thence north to 54° N. latitude thence west.

15. *North Aleutian Basin:* Lies in the eastern Bering Sea northwest of the Alaskan Peninsula and south of 59° N. latitude. It is bounded on the west by 165° W. longitude.

16. *St. George Basin:* Lies in the eastern Bering Sea northwest of the Aleutian Islands chain and is bounded on the north by 59° N. latitude and on the west by 174° W. longitude from 59° N. latitude to 56° N. latitude, thence east to 171° W. longitude, thence south It is bounded on the east by 165° W. longitude.

17. *Bower Basin:* Lies in the Bering Sea north of the Aleutian Islands chain It is bounded on the north by 56° N. latitude, on the east by 171° W. longitude, on the south by 53° N. latitude west to 174° E. longitude, thence north to 54° N. latitude, thence west.

18. *Aleutian Basin:* Lies in the Bering Sea north of the Bowers Basin area. It is bounded on the south by 56° N. latitude, and on the east by 174° W. longitude from 56° N. latitude to 56° N. latitude, thence west to 180° W. longitude, thence north.

19. *Navarin Basin:* Lies in the western Bering Sea west of St. Matthew Island and south of 63° N. latitude. It is bounded on the northwest by the U.S.-Russia Convention Line of 1867, on the

east by 174° W. longitude, on the west by 180° W. longitude, and on the south by 56° N. latitude.

20. *St. Matthew-Hall:* Bounded on the north by 63° N. latitude, on the west by 174° W. longitude, and on the south by 59° N. latitude.

21. *Norton Basin:* Lies south and southwest of the Seward Peninsula. It is bounded on the south by 62° N. latitude, on the west by the U.S.-Russia Convention Line of 1867, and on the north by 65° 34' N. latitude.

22. *Hope Basin:* Lies north of the Seward Peninsula and is bounded on the west by the U.S.-Russia Convention Line of 1867, on the north by 68° 17' N. latitude and on the south by 65° 34' N. latitude.

23. *Chukchi Sea:* Bounded on the south by 68° 17' N. latitude, on the west by the U.S.-Russia Convention Line of 1867. The northern boundary extends west along 71° N. latitude from the state territorial sea to 162° W. longitude, thence north from this juncture along 162° W. longitude.

24. *Beaufort Sea:* Lies offshore of Alaska in the Beaufort Sea and the Arctic Ocean. It is bounded on the west by the Chukchi Sea planning area and extends eastward to the limit of U.S. jurisdiction.

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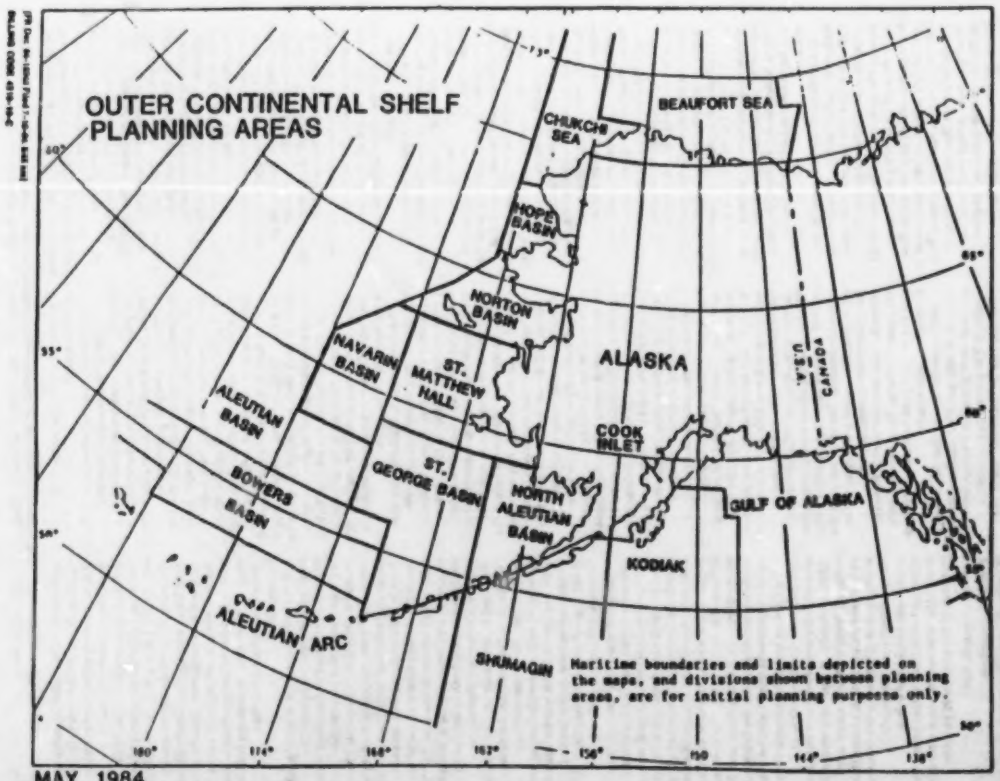
OUTER CONTINENTAL SHELF PLANNING AREAS

Maritime boundaries and limits depicted on the maps, and divisions shown between planning areas, are for initial planning purposes only.

MAY 1984

U.S. Department of the Interior
Minerals Management Service



MAY 1984

U.S. Department of the Interior

Minerals Management Service

Request for Comments on Appendix P: Analysis of Tract Selection and Areawide Leasing Approaches (an Appendix to the Secretarial Issue Document for the Upcoming Proposed 5-Year Outer Continental Shelf (OCS) Oil and Gas Leasing Program)

DATES: Comments must be received by September 13, 1985.

ADDRESSES: Comments should be submitted to the Deputy Associate Director for Offshore Leasing, Minerals Management Service, Room 4229, Mail Stop 641, 18th and C Streets, NW., Washington, D.C. 20240.

FOR FURTHER INFORMATION CONTACT: Copies of the Appendix may be requested by writing to the above address or by contacting Tim Redding at (202) 343-1072. Questions on the substance of the Appendix may be directed to Don Sarri at (202) 343-3526 or Ted Heintz at (202) 343-7258.

SUPPLEMENTARY INFORMATION: An initial version of the Secretarial Issue Document for the new 5-year program (including Appendix P) was issued on March 21, 1985. Based on comments received on that initial version and additional analysis, a revised version of Appendix P has been prepared and is now available for further public comment. Comments on the revised version of Appendix P have been requested from the Governors of all coastal States.

SUMMARY: The change in 1983 from tract selection to areawide OCS lease sales caused considerable controversy on several grounds. This appendix analyzes those aspects of the controversy concerning investment and revenues. It evaluates the extent to which experience with areawide leasing has achieved its objectives and borne out the concerns expressed about its effects. It also discusses the implications of the new 5-year leasing program.

The most important conclusions from this analysis are that areawide leasing may have caused:

- Substantial increases in the investments in leasing and exploration needed to reap the energy and economic benefits of OCS resources;
- A relatively small part of the total decline in bonuses observed in leasing during 1983 and 1984; and
- A substantial increase in the total return to the U.S. treasury from accelerated leasing of OCS oil and gas.

Central to the analysis is the concept of the OCS lands as an inventory of investment opportunities. An analytic framework is developed which accounts for changes in the inventory of unleased tracts that can occur as a result of changing economic conditions (particularly oil price expectations), changing geologic knowledge, and the different leasing rates that can occur. The status of the inventory depends not only on the economic and geologic conditions that make prospects valuable, but on the way in which tracts have been sold from the inventory in previous years. Changes in the Government's inventory of unleased tracts are reflected in changes in the characteristics of the tracts sold in subsequent sales. Thus, as sales proceed, the amount of acreage leased, its value, the cash bonus revenue collected by the Government, and the subsequent level of investment in exploration would be expected to change as the nature of the unleased inventory changed.

Two key objectives of areawide leasing were to expand the amount and location of acreage leased and to increase the rate of investment in exploration. Critics expressed related concerns that industry did not have the capital to expand its investment and that leases would be acquired, but not explored or developed until years later. This appendix examines data on the experience under tract selection and areawide leasing. It shows that during the 1979-1982 period, leasing and investment in exploration did not expand as price increases made more tracts attractive for investment. As a result, the Government's inventory of unleased acreage worth investing in grew in size and value. Areawide leasing in 1983 and 1984 substantially increased industry's investment in lease acquisition and exploration, particularly in the Gulf of Mexico. There is also evidence that there will continue to be increased exploration investment in the future, based on the exploration plans that have been submitted in recent years.

The buildup of the inventory in the 1979-1982 period and its drawdown in 1983-1984 also had important revenue consequences. Critics of areawide leasing charged that competition would be so thinned by offering much more acreage that bonus bids would decline and the fair market value requirement of section 18(a)(4) would be violated. This appendix shows that the restricted leasing in tract selection sales of the 1979-1982 period increased average bonus bids per acre, primarily by withholding tracts from sale while their value appreciated. Total revenues from bonuses in that period were limited because of the limited amount of acreage leased.

In contrast, areawide leasing in 1983 and 1984 drew down the inventory rapidly. This accelerated leasing resulted in receiving revenues much earlier than would have been the case under tract selection procedures. Bonuses have been received in the 1983-1984 period that would otherwise have been spread out over the 1985-1990 period. Ultimately, royalties and taxes will also be received earlier. This paper estimates that, under the actual leasing rates in the Central and Western Gulf of Mexico in 1983 and 1984, bonuses would have to have been increased, perhaps by as much as $0.5 million higher per tract, under the leasing rates of tract selection procedures to yield the same present value of revenues as will be realized by the Federal Government from areawide lease sales in those areas.

The drawdown in the inventory also resulted in decreasing average bids although total revenues from bonuses increased, particularly in 1983. Fewer high value tracts and more low value tracts were leased in subsequent sales. The trend of decreasing average bids began, however, in 1983, well before the start of areawide leasing. This appendix concludes that such variations in the average bid do not indicate a violation of the fair market value requirement. This provision does not require the Secretary to maximize bonus revenues by withholding tracts while their value appreciates. (In addition, the value of many tracts were probably decreasing during the 1980-1984 period because of declining oil price expectations and may have continued to decline in 1985.)

Critics of areawide leasing charged that it would thin competition by spreading a limited number of bidders and their limited capital over far more acreage. Less competition, they claimed, would mean lower bids and violation of the fair market value requirement of section 18(a)(4) of the OCS Lands Act. The Secretary and the courts recognized in 1982 that bonuses might decline under areawide leasing. The court rejected the claim that this meant a violation of the fair market value requirement. Nevertheless, the relationship between the pace of leasing, the number of bids, and the amount paid in bonuses remains a matter of controversy.

This appendix shows that the average number of bids per tract declined during the 1980-1984 period as average bids declined. The percentage of tracts receiving one bid increased while the percentage receiving two or more bids decreased. These trends began before the implementation of areawide leasing and continued in areawide sales. In addition, the sixfold increase in the minimum bid implemented in 1982 would be expected to lead to fewer bids per tract on average. It is difficult, however, to isolate the effects of fewer bids on the bid levels from the effects of declining tract values on the number of bids. Since average bids declined more on tracts receiving more than two bids than on tracts receiving only one or two bids, it is reasonable to conclude that most of the decline in average bids was caused by factors other than competition.

A statistical analysis of leasing and bidding data was performed to determine whether and to what extent the implementation of areawide leasing caused a reduction in bonuses. The conclusion from an approach using well accepted statistical techniques is that there is little evidence that areawide leasing was the primary cause of the substantial decline in bonuses. Further analysis using improved data and more sophisticated methods is needed to overcome important limitations identified in this analysis. The results at this stage, in the analysis, however, indicate that the bonus declines associated with areawide leasing were, in all likelihood, much smaller than the revenue gains from earlier leasing. There is good evidence that the Treasury will come out ahead.

Using the inventory concept, this appendix shows that if oil prices are expected to be stable and past areawide leasing has drawn down the inventory of unleased acreage, then areawide and tract selection procedures could cause similar types and amounts of acreage to be leased in future sales. The patterns of competition, the levels of bids, and the implications for meeting the fair market value requirement would also be similar.

If oil prices and price expectations rise, however, tract selection and areawide leasing procedures could yield different results. If tract selection sales withhold leasable tracts while tract values were appreciating, competition would tend to increase as the value of tracts offered rose. Areawide procedures would allow less appreciation in tract values before they draw bids, thus would cause a smaller increase in the number of bidders.

Dated: August 14, 1985.

William D. Bettenberg,

Director, Minerals Management Service.

[FR Doc. 85-19292 Filed 8-16-85; 8:45 am]

BILLING CODE 4310-MR-M

APPENDIX N

PLANNING AREA BOUNDARIES

1. North Atlantic: Extends south from the juncture of the territorial sea at approximately 71° W longitude to 39° N latitude thence east to the juncture of an extension of the U.S.-Canada Maritime Boundary thence north along that line and the maritime boundary to the territorial sea thence following the territorial sea to the point of origin.

2. Mid-Atlantic: Extends east from the juncture of the territorial sea at approximately 35° N latitude to 70° W longitude thence north to approximately 37° N latitude thence east to 68° W longitude thence north to approximately 38° N latitude thence east to 66° W longitude thence north to 39° N latitude thence west to 71° W longitude thence north to the territorial sea thence along the territorial sea to the point of origin.

3. South Atlantic: East from the juncture of the territorial sea at approximately 35° N latitude to 70° W longitude thence south to 34° N latitude thence west to 72° W longitude thence south to 32° N latitude thence west to 74° W longitude thence south to 31° N latitude thence west to 78° W longitude thence south to 28°17'10" N latitude thence west to the territorial sea limits thence north along the territorial sea to the point of origin.

4. Straits of Florida: East from the juncture of the territorial sea at 28°17'10" N latitude to 79°11'24" W longitude thence southwest along the line of U.S. jurisdiction to approximately 81°13' W longitude at 23°55' N latitude thence west to 83° W longitude thence north to the territorial sea abutting the Dry Tortugas thence east to the limits of the territorial sea thence along the territorial sea to the point of origin.

5. Eastern Gulf of Mexico: South from the territorial sea at approximately 87°45' W longitude to approximately 29° N latitude thence west to approximately 87°55' W longitude thence south to approximately 26° N latitude thence east to approximately 85°55' W longitude thence south to the limit of U.S. jurisdiction thence southeast to approximately 83°55' W longitude at approximately 23°55' N latitude thence east to 83° W longitude thence north to the limits of the territorial sea thence east to approximately 82°25' W longitude thence north and east along the territorial sea to the limits of U.S. jurisdiction thence along the territorial sea to the point of origin.

6. Central Gulf of Mexico: South from the territorial sea at approximately 87°45' W longitude to approximately 29° N latitude thence west to approximately 87°55' W longitude thence south to approximately 26° N latitude thence west to approximately 91°55' W longitude, except that between approximately 88°23' W longitude and 91°05' W longitude the boundary is the U.S.-Mexico Provisional Maritime Boundary, thence north to approximately 27°55' N latitude thence generally west to approximately 93°25' W longitude thence northwest to the juncture of the territorial sea at approximately 93°50' W longitude thence east along the territorial sea to the point of origin.

7. Western Gulf of Mexico: East from the territorial sea along the U.S.-Mexico Provisional Maritime Boundary to 93°26'42.19" W. longitude thence along approximately 26° N latitude to approximately 91°55' W longitude thence north to approximately 27°55' N latitude thence generally west to approximately 93°25' W longitude thence northwest to the juncture of the territorial sea at approximately 93°50' W longitude thence along the territorial sea to the point of origin.

8. Southern California: West along a line extending from the territorial sea at approximately 35°47' N latitude to approximately 124° W longitude thence south to approximately 34°58' N latitude thence east to approximately 122° W longitude thence south to approximately 32°55' N latitude thence east to approximately 121°40' W longitude thence south to approximately 32°40' N latitude thence east to approximately 120°20' W longitude thence south to approximately 32°10' N latitude thence east to 120° W longitude thence south to the U.S.-Mexico Provisional Maritime Boundary thence along the U.S.-Mexico Provisional Maritime Boundary to the territorial sea thence along the territorial sea to the point of origin.

9. Central California: West along a line extending from the territorial sea at approximately 35°47' N latitude to approximately 124° W longitude thence north to approximately 37°59' N latitude thence west to approximately 126° W longitude thence north to approximately 38°46' N latitude thence east to the territorial sea thence along the territorial sea to the point of origin.

10. Northern California: West along a line extending from the territorial sea at approximately 38°46' N latitude to approximately 128° W longitude thence north to approximately 42° N latitude thence east to the territorial sea thence along the territorial sea to the point of origin.

11. Washington-Oregon: West along a line extending from the territorial sea at approximately 42° N latitude to 128° W longitude thence north to the limits of U.S. jurisdiction thence northeast along the limits of U.S. jurisdiction to 46°29'37.19" N latitude at 124°45'33.19" W longitude thence due south to the territorial sea thence along the territorial sea to the point of origin.

12. Beaufort Sea: West from the juncture of U.S. jurisdiction at 73° N latitude to 162° W longitude thence south to 71° N latitude thence east to the limits of the territorial sea thence east to the limit of U.S. jurisdiction thence north to the point of origin.

13. Chukchi Sea: East from the U.S.-Russia Convention Line along 73° N latitude to 162° W longitude thence south to 71° N latitude thence east to the limits of the territorial sea thence generally southwest to approximately 68°20' N latitude at 167° W longitude thence west to the U.S.-Russia Convention Line thence north to the point of origin.

14. Hope Basin: Extends west from the juncture of the territorial sea at 68°20' N latitude to the U.S.-Russia Convention Line thence south along the U.S.-Russia Convention Line to 65°35' N latitude thence east to the limits of the territorial sea thence along the territorial sea to the point of origin.

15. Norton Basin: Extending west from the juncture of 65°35' N latitude at 166°15' W longitude to the U.S.-Russia Convention Line thence generally southwest along that line to approximately 63° N latitude at 175° W latitude thence east to the territorial sea thence along the territorial sea to the point of origin.

16. Navarin Basin: Extends southwest from the juncture of approximately 63° N latitude at the U.S.-Russia Convention Line along that line to 180° longitude thence south to approximately 58° N latitude thence east to 174° W longitude thence north to approximately 63° N latitude thence west to the point of origin.

17. St. Matthew-Hall: West from the territorial sea at approximately 63° N latitude at 165° W longitude to 174° W longitude thence south to approximately 59° N latitude thence east to the territorial sea thence following the territorial sea to the point of origin.

18. St. George Basin: South from 59° N latitude at 174° W longitude to 56° N latitude thence east to 171° W longitude thence south to approximately 52°35' N latitude thence east to the limits of the territorial sea thence following the territorial sea east to approximately 170°30' W longitude at 52°40' N latitude thence east to the limit of the territorial sea at approximately 52°46' N latitude thence following the territorial sea to approximately 52°48' N latitude thence east to the limit of the territorial sea thence northeast to 165° W longitude thence north to 59° N latitude thence west to the point of origin.

19. North Aleutian Basin: West from 161°52' W longitude at approximately 59° N latitude to 165° W longitude thence south to the intersection with the territorial sea thence following the territorial sea to the point of origin.

20. Shumagin: Extends south from a point at approximately 54°30' N latitude and 165° W longitude to 50° N latitude thence east to 159° W longitude thence north to 51° N latitude thence east to 156° W longitude thence north to 57° N latitude thence west to the territorial sea thence southwest along the territorial sea to the point of origin.

21. Cook Inlet: Extends east from approximately 56°57' N latitude at 156°25' W longitude to the intersection with the territorial sea thence generally northeast along the territorial sea to approximately 152°27' W longitude thence north to the territorial sea thence around the territorial sea to approximately 59° N latitude at 152° W longitude thence north to the territorial sea thence following the territorial sea to the point of origin.

22. Kodiak: Extends east from 57° N latitude at 156° W longitude to the territorial sea thence generally northeast along the territorial sea to approximately 152°27' W longitude thence north to the territorial sea thence around the territorial sea to approximately 59° N latitude thence east to 148° W longitude thence south to 58° N latitude thence east to 147° W longitude thence south to 53° N latitude thence west to 150° W longitude thence south to 52° N latitude thence west to 156° W longitude thence north to the point of origin.

23. Gulf of Alaska: Extends south from approximately 151°55' W longitude at 59°05' N latitude to the territorial sea at approximately 59° N latitude thence east to 148° W longitude thence south to 58° N latitude thence east to 147° W longitude thence south to 53° N latitude thence east to 141° W longitude thence generally northeast along the fishery conservation line to the territorial sea thence along the territorial sea to the point of origin.

24. Aleutian Basin: East from the juncture of approximately 56° N latitude at the U.S.-Russia Convention Line to 174° W longitude thence north to approximately 58° N latitude thence west to 180° longitude thence north to the juncture of the U.S.-Russia convention Line thence along that line to the point of origin.

25. Bowers Basin: East from the juncture of approximately 56° N latitude at the U.S. Russia Convention line to 171° W longitude thence south to approximately 53° N latitude thence west to 174° E longitude thence north to approximately 54° N latitude thence west to the U.S.-Russia Convention Line thence along that line to the point of origin.

26. Aleutian Arc: East from the juncture of the U.S.-Russia Convention Line at approximately 54° N latitude to 174° E longitude thence south to approximately 53° N latitude thence east to 171° W longitude thence south to approximately 52°35' N latitude thence east to the limits of the territorial sea thence following the territorial sea east to approximately 170°30' W longitude at 52°40' N latitude thence east to the limit of the territorial sea at approximately 52°46' N latitude thence following the territorial sea to approximately 52°48' N latitude thence east to the limit of the territorial sea thence northeast to 165° W longitude thence south to approximately 50° N latitude thence west to approximately 167° E longitude thence north to the U.S.-Russia Convention Lire thence along that line to the point of origin.

APPENDIX O

LEASING DEFERRALS MADE BY SALE IN THE JULY 1982 5-YEAR OCS OIL AND GAS LEASING PROGRAM (JULY 1982 - OCTOBER 1985)

LEASING DEFERRALS MADE BY SALE IN THE JULY 1982 5-YEAR OCS OIL AND GAS LEASING PROGRAM (JULY 1982 - OCTOBER 1985)

Since approval of the July 1982 5-Year Outer Continental Shelf (OCS) Oil and Gas Leasing Program, 32 lease sales have undergone some or all of the prelease planning which determines the size, timing, location, terms, and conditions of each sale. Leasing deferrals can be made at various steps in this process to reflect concerns about sale size and location. Many of the sales have been modified by deferrals--the removal of blocks and acreage, for any reason, from a sale. This appendix delineates the deferrals which have occurred from July 1982 through October 3, 1985 in the current leasing program. Table 1 provides a summary of deferrals to date.

The 32 sales addressed here encompass two different approaches to offshore leasing: tract selection and areawide. Table 2 shows that the bulk of leasing deferrals in tract selection sales occurred early in the prelease process, with the primary emphasis on deferrals after the Call for Nominations. Sales conducted under areawide leasing are likely to have deferrals made later or more often throughout the entire prelease planning process. Since Secretary Clark's announcement in January 1984 that early resolution of conflict would be pursued, these deferrals have tended to occur earlier and earlier.

The reasons for deferring blocks from each sale vary, but generally deferrals result from concerns expressed by affected States and by Federal Agencies, principally the Department of Defense (DOD). Problems with disputed Federal/State or international boundaries have also led to deferrals, although the number of blocks involved in these disputes is often few.

Acreage data and block statistics in this appendix came from the Minerals Management Service (MMS) official sale files and from the records and files in the four MMS regional offices. Table 2 displays the percentage of blocks and acreage deferred at each prelease step for the 32 sales and indicates the general reason for the deferrals. Unusual characteristics of sales are also noted.

A note of caution: the reasons given here for deferrals are intended as general summaries and should not be interpreted as an official MMS or Department of the Interior explanation of those deferrals. Letters, memoranda, and press releases from each sale contain the official reasons for deferral. The summaries presented here do not supersede the official files.

Table 1: Percent of Acreage of Proposed Lease Sale Areas Deferred During Presale Process (July 1982 - October 1985)

Sale (Area)	Beginning Acreage (in millions)	Total Deferred as of October 3, 1985 (in millions)	Total Acreage Remaining (in millions)	Percent Acreage Deferred
RS-2	3.50	0.36	3.14	10.38
52 (NA)	16.97	16.97	0	100.00
76 (MA)	50.10	27.43	22.67	54.75
78 (SA)	81.16	60.76	20.40	74.87
82 (NA)	60.00	60.00	0	100.00
90 (SA)	99.10	86.60	12.50	87.35
111 (MA)	81.50	61.50	20.00	75.46
69 (GOM)	134.40	133.10	1.40	99.03
72 (CGOM)	38.00	0.20	37.87	0.53
74 (WGOM)	33.00	0	33.00	0
79 (EGOM)	56.98	7.97	50.63*	13.50
81 (CGOM)	45.06	0.22	34.74*	0.49
84 (WGOM)	35.27	0.59	30.04*	1.70
94 (EGOM)	58.97	20.00	37.00*	33.90
98 (CGOM)	45.06	9.05	24.01*	20.10
102 (WGOM)	35.27	1.60	27.20*	4.54
104 (CGOM)	45.06	0	45.06	0
105 (WGOM)	35.27	0.60	34.67	1.70

* Totals do not add because beginning acreage figures include leased blocks which were not withdrawn until the proposed Notice of Sale.

MA = Mid-Atlantic
NA = North Atlantic
SA = South Atlantic

GOM = Gulf of Mexico
CGOM = Central Gulf of Mexico
EGOM = Eastern Gulf of Mexico
WGOM = Western Gulf of Mexico

RS-2 = Reoffering Sale 2

Table 1 (continued): Percent of Acreage of Proposed Lease Sale Areas Deferred During Presale Process (July 1982 - October 1985)

Sale (Area)	Beginning Acreage (in millions)	Total Deferred as of October 3, 1985 (in millions)	Total Acreage Remaining (in millions)	Percent Acreage Deferred
73 (CC)	24.14	23.37	0.77	96.81
80 (SC)	22.50	19.35	3.15	86.01
57 (NB)	27.20	24.82	2.38	91.25
70 (SGB)	46.00	43.31	2.69	94.15
71 (BS)	13.87	12.05	1.83	86.84
83 (NV)	37.09	9.04	28.05	24.38
85 (CS)	29.45	0	29.45	0
87 (BS)	49.36	41.59	7.73	84.25
88 (GA)	137.68	123.95	13.72	90.03
69 (SGB)	70.24	5.00	65.00	7.12
92 (NAB)	32.45	26.85	5.60	82.73
97 (BS)	52.00	31.00	21.00	59.62
100 (NB)	19.20	9.41	9.79	49.00
107 (NV)	28.10	0	28.10	0

CC = Central California
SC = Southern California

BS = Beaufort Sea
CS = Chukchi Sea
GA = Gulf of Alaska/Cook Inlet

NAB = North Aleutian Basin
NB = Norton Basin
NV = Navarin Basin
SGB = St. George Basin

Table 2: Percent Deferred as of October 3, 1985 by Planning Stage for Sales in the July 1982 5-Year OCS Oil and Gas Leasing Schedule

Sale and Area		% deferred from Call	% deferred from AID[1]	% deferred from PNS[2]	Total % deferred	Notes
RS-2	Acres:		8.7	1.8	10.4	b,e
	Blocks:	NA	8.7	1.8	10.4	
52[3]: North Atlantic	Acres:	82.0	0	9.7	100.0	a,b
	Blocks.	82.2	0	9.6	100.0	c,h
76: Mid-Atlantic	Acres:	49.3	10.6	0.05	54.7	b,c
	Blocks:	48.6	10.4	0.05	54.0	e,f
78: South Atlantic	Acres:	59.2	0.3	38.8	74.9	b,c
	Blocks:	59.2	1.7	37.4	74.9	e,f
82: North Atlantic	Acres:	59.2	44.9	51.9	100.0	b,c,d
	Blocks:	60.1	42.7	53.9	100.0	e,f,h
90: South Atlantic	Acres:	58.8	69.4			c,f
	Blocks:	59.2	69.6			g,i
111: Mid-Atlantic	Acres:	75.1				b,c
	Blocks:	73.5				f,i
69[3]: Gulf of Mexico	Acres:	99.0	0	Part I 0	99.0	a,e
	Blocks:	99.0	0	Part II 0.7	99.0	
				Part I 0		
				Part II 1.5		
72: Central Gulf of Mexico	Acres:	0	0.5	0	0.5	e,j
	Blocks:	0	0.6	0	0.6	
74: Western Gulf of Mexico	Acres:	0	0	0	0	j
	Blocks:	0	0	0	0	

Notes:
a - Deferral made as part of tract selection process.
b - Deferral made at request of a State.
c - Deferral made at request of the DOD/National Aeronautics and Space Administration (NASA).
d - Deferral made by congressional moratoria.
e - Deferral made for administrative reasons (boundary litigation concerns, mapping errors, etc.)
f - Deferral made because only geologically favorable acreage was considered after Call for Information (areawide lease sale).
g - Deferral made by Secretary for other reasons.
h - Sale cancelled.
i - Sale still in prelease planning stages.
j - Original Gulf-wide sale became a planning area specific sale.

[1] AID = Area Identification
[2] PNS = Proposed Notice of Sale
[3] Tract Selection Sale

NA = Not Applicable

Table 2 (continued): Percent Deferred as of October 3, 1985 by Planning Stage for Sales in the July 1982 5-Year OCS Oil and Gas Leasing Schedule

Sale and Area		% deferred from Call	% deferred from AID[1]	% deferred from PNS[2]	Total % deferred	Notes
79: Eastern Gulf of Mexico	Acres:		0	13.5	13.5	c
	Blocks:	NA	0	14.4	14.4	
81: Central Gulf of Mexico	Acres:	0	0	0.6	0.5	b,d
	Blocks:	0	0	1.1	0.8	
84: Western Gulf of Mexico	Acres:	0	1.7	0	1.7	a,d
	Blocks:	0	2.0	0	2.0	
94: Eastern Gulf of Mexico	Acres:	0	33.9			a,e
	Blocks:	0	35.6			f,g
98: Central Gulf of Mexico	Acres:	0	0	27.4	20.1	d,e
	Blocks:	0	0	26.3	19.0	
102: Western Gulf of Mexico	Acres:	0.03	1.7	3.5	4.5	a,d,f,g
	Blocks:	0.03	1.9	3.5	4.7	
104: Central Gulf of Mexico	Acres:	0				f
	Blocks:	0				
105: Western Gulf of Mexico	Acres:	1.7				a,d,f
	Blocks:	2.0				

Notes:
a - Deferral made at request of a State.
b - Deferral made at request of the DOD/NASA.
c - Deferral made by congressional moratoria.
d - Deferral made for administrative reasons (boundary litigation concerns, mapping errors, etc.)
e - Deferral made by Secretary for other reasons.
f - Sale still in prelease planning stages.
g - Deferral included deepwater acreage over 2,400 meters.

[1] AID = Area Identification
[2] PNS = Proposed Notice of Sale
NA = Not Applicable

Table 2 (continued): Percent Deferred as of October 3, 1985 by Planning Stage for Sales in the July 1982 5-Year OCS Oil and Gas Leasing Schedule

Sale and Area		% deferred from Call	% deferred from AID[1]	% deferred from PNS[2]	Total % deferred	Notes
73[4]: Central California	Acres:	62.0	81.5	54.7	96.8	a,b
	Blocks:	62.6	83.1	51.6	96.9	c,d,e
80: Southern California	Acres:	46.4	66.4	23.1	86.0	b,c,d
	Blocks:	46.6	69.2	46.4	84.3	e,f
57[3]: Norton Basin	Acres:	91.0	0	2.6	91.3	a,b
	Blocks:	90.9	0	2.6	91.1	
70[3]: St. George Basin	Acres:	94.3	0	0	94.2	a
	Blocks:	94.2	0	0	94.2	
71[3]: Beaufort Sea	Acres:	86.8	0	1.4	86.8	a,e
	Blocks:	84.9	0	3.4	86.3	
83: Navarin basin	Acres:	20.3	4.7	0.2	24.4	c,f
	Blocks:	20.5	4.7	0.2	24.4	
85: Chukchi Sea	Acres:	0				g
	Blocks:	0				
87: Beaufort Sea	Acres:	63.5	55.8	2.5	84.3	b,f
	Blocks:	62.8	54.9	2.5	83.6	

Notes:
a - Deferral made as part of tract selection process.
b - Deferral made at request of a State.
c - Deferral made at request of the DOD/NASA.
d - Deferral made by congressional moratoria.
e - Deferral made for administrative reasons (boundary litigation concerns, mapping errors, etc.)
f - Deferral made because only geologically favorable acreage was considered after Call for Information (areawide lease sale).
g - Sale cancelled or withdrawn from schedule.

[1] AID = Area Identification
[2] PNS = Proposed Notice of Sale
[3] Tract Selection Sale
[4] Sale 73 started as a Tract Selection Sale but was then changed to a (modified) Areawide Sale. It also started as an all California sale and later was changed to Central and Northern California and finally to just Central California.

Table 2 (continued): Percent Deferred as of October 3, 1985 by Planning Stage for Sales in the July 1982 5-Year OCS Oil and Gas Leasing Schedule

Sale and Area		% deferred from Call	% deferred from AID[1]	% deferred from PNS[2]	Total % deferred	Notes
88: Gulf of Alaska/ Cook Inlet	Acres:	81.4	46.3			a,b,c
	Blocks:	80.8	46.2			d,e,f
89: St. George Basin	Acres:	0	7.1			
	Blocks:	0	8.6			b,e
92: North Aleutian Basin	Acres:	82.7	0			a,d,e
	Blocks:	83.4	0			
97: Beaufort Sea	Acres:	59.6				c,e
	Blocks:	56.3				
100: Norton Basin	Acres:	49.0				a,c,e
	Blocks:	51.5				
107: Navarin Basin	Acres:	0				e
	Blocks:	0				

Notes:
a - Deferral made at request of a State.
b - Deferral made for administrative reasons (boundary litigation concerns, mapping errors, etc.)
c - Deferral made because only geologically favorable acreage was considered after Call for Information (areawide lease sale).
d - Deferral made by Secretary for other reasons.
e - Sale still in prelease planning stages.
f - Sale 88 has been placed on hold.

[1] AID = Area Identification
[2] PNS = Proposed Notice of Sale

APPENDIX P

ANALYSIS OF THE PACE OF LEASING AND DEVELOPMENT

Effects on Investments, Economic Benefits, Revenue and Fair Market Value

ANALYSIS OF THE PACE OF LEASING AND DEVELOPMENT

Effects on Investments, Economic Benefits, Revenue and Fair Market Value

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Executive Summary

The change in 1983 from smaller tract selection OCS lease sales to areawide sales caused considerable controversy on several grounds. Although sale procedures were modified in 1984 and 1985 to focus sales on promising acreage, substantial acreage was still offered in some areas and controversy over the pace of leasing continued. In a report published in July 1985, the General Accounting Office (GAO) concluded that areawide leasing had increased the pace of exploration but had reduced competition and bonuses. It recommended that the Secretary consider effects in relation to anticipated benefits. This appendix analyzes those aspects of the pace of leasing concerning investment, economic benefits, fair market value and revenues. It evaluates the extent to which experience with areawide leasing has achieved its objectives and borne out the concerns expressed about its effects. It also discusses the implications for the new 5-year leasing program.

The most important conclusions from this analysis are that the larger sales typical of areawide and focused leasing have caused:

- substantial increases in the investments in leasing and exploration needed to reap the energy and economic benefits of OCS resources;
- a substantial increase in the benefits to the U.S. economy that can be expected to result from development of OCS oil and gas;
- a substantial increase, perhaps more than $7.5 million per tract, in the total return to the U. S. Treasury from leasing in the Central and Western; Gulf of Mexico; and
- at most, a relatively small part of the total decline in bonuses observed in leasing during 1983 through 1985.

Areawide and focused leasing were most effective in increasing investment in areas with proven oil and gas deposits and in areas where the marginal probability of finding hydrocarbon is high. Focused leasing, therefore, is expected to yield most of the economic benefits of areawide leasing.

Central to the analysis is the concept of the OCS lands as an inventory of investment opportunities that can yield varying returns and economic benefits. An analytic framework is developed which accounts for changes in the inventory of unleased tracts that can occur as a result of changing economic conditions (particularly oil price expectations), changing geologic knowledge, and the different leasing rates that can occur. The status of the inventory depends not only on the economic and geologic conditions that make prospects valuable, but on the way in which tracts have been sold from the inventory in previous years. Changes in the Government's inventory of unleased tracts are reflected in changes in the characteristics of the tracts sold in subsequent sales. Thus, as sales proceed, the amount of acreage leased, its value, the cash bonus revenue collected by the Government and the subsequent level of investment in exploration and the resulting economic benefits would be expected to change as the nature of the unleased inventory changed.

Two key objectives of areawide and focused leasing were to expand the amount and location of acreage leased and to increase the rate of investment in exploration. Critics expressed related concerns that industry did not have the capital to expand its investment and that leases would be acquired, but not explored or developed until years later. This appendix examines data on the experience under tract selection sales in the 1976-1982 period compared with the larger sales of the 1983-1985 period. It shows that during the 1976-1982 period, OCS leasing and investment in exploration did not expand much as price increases made more tracts attractive for investment. As a result, the Government's inventory of unleased acreage worth investing in grew in size and value. Areawide and focused lease sales in 1983 through 1985 substantially increased industry's investment in lease acquisition and exploration, particularly in the Gulf of Mexico. There is also evidence, based on the exploration plans that have been submitted in recent years, that there will continue to be a higher level of exploration investment in the future.

The different rates of investment in exploration that can occur under different approaches to leasing can be expected to result in different benefits to the economy. Earlier exploration can be expected to be followed by earlier discovery of those oil and gas deposits that are economic to produce. Earlier production and realization of the economic benefits from less costly domestic oil and gas production follow. This appendix analyzes the effects of different leasing rates on the timing and value of the benefits to the economy. A comparison is made for oil and gas resources in the Gulf of Mexico between a rate of leasing typical of the 1982 5-Year Leasing Program and the proposed 1987 program on the one hand and continued leasing at a slower rate typical of tract selection procedures used until 1983 on the other. The more rapid scenario yields gains of $15 billion to over $30 billion in total economic benefits derived from development of these oil and gas resources.

The buildup of the inventory in the 1976-1982 period and its drawdown in 1983-1985 also had important revenue consequences. Critics of areawide leasing charged that competition would be so thinned by offering much more acreage that bonus bids would decline and the fair market value requirement of Sec. 18(a)(4) would be violated. The GAO estimated that the decline in bonuses caused by areawide leasing was $3.1 million per tract, accounting for about 20 percent of the total observed decline. The statistical analysis supporting this estimate is reviewed in this appendix. Numerous weaknesses are found which undermine confidence that the estimates correctly measure the bonus effect of areawide leasing.

This appendix shows that the restricted leasing in tract selection sales of the 1976-1980 period increased average bonus bids per acre, primarily by withholding tracts from sale while their value appreciated. Total revenues from bonuses in that period were limited because of the limited amount of acreage leased. In contrast, areawide and focused leasing in 1983, 1984 and 1985 drew down the inventory rapidly. This accelerated leasing resulted in receiving revenues much earlier than would have been the case under tract selection procedures. Bonuses have been received in the 1983-1985 period that would otherwise have been spread out over the 1983-1994 period. Ultimately,

royalties and taxes will also be received earlier. This paper estimates that under the actual leasing rates in the Central and Western Gulf of Mexico in 1983 and 1984, bonuses would have to be higher, perhaps by more than $7.5 million per tract, under the leasing rates typical of tract selection procedures to yield the same present value of revenues as will be realized by the Federal Government from areawide and focused lease sales in those areas. Thus, even if the GAO estimate of a $3.1 million decline in average bonuses were correct, the Treasury will still come out ahead in the long run.

Critics of a faster pace of leasing charged that it would thin competition by spreading a limited number of bidders and their limited capital over far more acreage. Less competition, they claimed, would mean lower bids and violation of the fair market value requirement of Sec. 18(a)(4) of the OCS Lands Act. The Secretary and the Courts recognized in 1982 that bonuses might decline under areawide leasing. The Court rejected the claim that this meant a violation of the fair market value requirement. Nevertheless, the relationship between the pace of leasing, the number of bids and the amount paid in bonuses remains a matter of controversy.

The draw down in the inventory resulted in decreasing average bids although total revenues from bonuses increased, particularly in 1983. Fewer high value tracts and more low value tracts were leased in subsequent sales. The trend of decreasing average bids began, however, in 1980, well before the start of areawide leasing. This appendix concludes that such variations in the average bid do not indicate a violation of the fair market value requirement. This provision does not require the Secretary to maximize bonus revenues by withholding tracts while their value appreciates. In addition, the values of many tracts were decreasing during the 1983-1985 period because of declining oil price expectations.

This appendix shows that the average number of bids per tract declined during the 1980-1984 period as average bids declined. The percentage of tracts receiving one bid increased while the percentage receiving two or more bids decreased. These trends began before the implementation of areawide leasing and continued in areawide and focused lease sales. In addition, the sixfold increase in the minimum bid implemented in 1982 would be expected to lead to somewhat fewer bids per tract, on average. It is difficult, however, to isolate the effects of fewer bids on the bid levels from the effects of declining tract values on the number of bids. Since average bids declined more on tracts receiving more than two bids than on tracts receiving only one or two bids, it is reasonable to conclude that most of the decline in average bids was caused by factors other than competition.

Using the inventory concept, this appendix shows that if oil prices are expected to be stable and past areawide leasing has drawn down the inventory of unleased acreage, then areawide, focused and tract selection procedures could cause similar types and amounts of acreage to be leased in future sales. The patterns of competition, the levels of bids and the implications for meeting the fair market value requirement would also be similar.

If oil prices and price expectations rise, however, tract selection procedures would yield different results than focused or areawide sales. If tract selection sales withheld leasable tracts while tract values were appreciating,

competition would tend to increase as the value of tracts offered rose. Average bonuses would increase as the value of the unleased inventory appreciated. The delayed leasing and investment in exploration caused by holding tracts in the inventory as they appreciated would, in general, reduce the benefits to the economy in comparison with more rapid leasing and investment. Areawide and focusing-on-promising acreage procedures would allow less appreciation in tract values before they drew bids, thus would cause a smaller increase in the number of bidders. Average bonuses would increase less, but the rate of investment would be greater. This could be expected to yield greater total revenues to the Treasury and greater benefits to the U.S. economy.

ANALYSIS OF THE PACE OF LEASING AND DEVELOPMENT

Effects on Investments, Economic Benefits, Revenue and Fair Market Value

I. Introduction

The pace of leasing for OCS oil and gas has been a matter of controversy for over a decade, focusing on the size of lease sales and their frequency. Debates arose in 1974 when the Government proposed to lease 10 million acres a year in response to OPEC oil price hikes. The acreage actually leased, using Interior's tract selection procedures, did not exceed 2 million acres per year until 1981, the second year of the leasing program approved in 1980. Further controversy arose over the areawide leasing program approved in 1982. Under this program 6.6 million acres were leased in 1983. In 1984 8.2 million acres were leased and in 1985, 3.2 million.

The objective of areawide leasing was to allow the private sector a wider choice in the location and the rate of investments in exploration and development of OCS oil and gas prospects. A procedural change was made in order to achieve this objective, allowing the higher leasing rates of 1983 and 1984. The tract selection sale procedures used in prior years had restricted the location and the amount of acreage offered. For tract selection sales, tract value estimates were prepared for all tracts to be offered and were completed prior to the date of the sale. As a result of such administrative constraint, less than half of the tracts nominated by potential bidders were offered in the subsequent sale. The tracts selected from those nominated tended to be those that received nominations from more firms.

The removal of such administrative constraints on the size of lease sales allowed decisions on the acreage to be offered in specific lease sales to be focused on the potential for oil and gas discovery and its benefits on one hand and the potential environmental effects on the other. In particular, it allowed tracts to be offered even though they had modest potential so long as the environmental risks were judged to be in reasonable balance. Firms were not prevented from investing in lease acquisition and exploration in areas for which they had developed unique information about the resource potential unless there was judged to be a substantial environmental risk.

In January, 1984, and again in March, 1985, the areawide sale procedures were modified to provide for earlier consultation concerning, and resolution of, conflicts over the acreage to be offered in a sale. The resulting procedures are intended to identify promising acreage while removing acreage that has little oil and gas potential or high conflict with other resources and uses. In general, the procedures to focus on promising acreage result in the offering of less acreage.

Most of the controversy over the pace of OCS leasing stems from the fear of extensive environmental damage and onshore impacts. The debate, however, has expanded to include a wide range of issues, among them the danger of premature development and the need to conserve resources for future generations, the potential effects of capital limitations on the pace and efficiency of

exploration and development, the effect of large lease offerings on the competitive lease sale process and its ability to yield appropriate revenues to the Federal Government, and the administrative work load, particularly in State and local governments, necessitated by larger and more frequent sales.

On July 15, 1985 the General Accounting Office (GAO) issued a report entitled "Early Assessment of Interior's Area-Wide Program For Leasing Offshore Lands." This report evaluated the effects of areawide leasing on the amount of acreage leased, exploration activity, bidding competition and bonus revenues. It also examined the presale planning and public participation processes and the bid acceptance procedures used in areawide leasing. The GAO concluded, in particular, that areawide leasing had sharply increased the pace of exploration and reduced competition and bonus bids. It recommended "that the Secretary of the Interior consider the effects [of areawide leasing and other approaches] on competition and bid revenues in relation to anticipated benefits, and report his findings to the Congress."

This appendix focuses primarily on the investment, economic and revenue aspects of the pace of leasing issue. The question of timing of investments, which is fundamental to economically efficient development of OCS oil and gas deposits, is discussed in Appendix F. As part of the analysis of economic benefits, Appendix F develops economic principles for sequencing development and guidelines for formulating leasing programs that deal with the problems of premature and tardy investments. Appendix P develops additional concepts used to analyze the effects of the pace of leasing on investments and resulting economic benefits as well as on competition and revenues.

This appendix begins, in Section II, by developing a framework for assessing the consequences of different leasing rates for investments and economic benefits. It draws on Appendix F for concepts of the relationship between the timing of investments and resulting economic benefits as well as the economic characteristics of OCS oil and gas resources. This framework is intended to assist in the analysis of the experience under tract selection sales of the 1970's and early 1980's and larger sales of 1983 through 1985. More importantly, it will provide a basis for evaluating the possible consequences of leasing at different rates under the conditions likely to prevail in the 1987-1991 period of the third 5-year program.

The third section of this appendix applies this framework to the analysis of the investments in lease acquisition and exploration that have occurred as a result of past leasing. It provides estimates of the differences in economic benefits that are expected to result from different rates of leasing for the Secretary to consider as recommended by the GAO. The analysis shows that more rapid leasing has increased the rate of investment in exploration, particularly in the Gulf of Mexico. A comparison of the economic benefits likely to result with those of a slower leasing program shows gains in the Gulf of Mexico of $15 billion to over $30 billion. Section III also assesses the implications for the effects of future leasing under procedures ranging from areawide to tract selection.

Section IV develops a framework for assessing the effects of the rate of leasing on Federal revenues and fair market value. Issues about fair market value are often stated in the form of a charge that a rapid rate of leasing

(such as that in 1983, 1984, and 1985) thins competition and depresses the cash bonus bids made for OCS leases and thus undermines the Secretary's ability to "assure receipt of fair market value" as he is required to do by the OCS Lands Act (Sec. 18(a)(4)). Section V evaluates the evidence regarding such effects including the finding that areawide leasing caused a reduction in bonuses that was provided by the July 1985 GAO report. It is shown that the total value of Government revenues is likely to have been increased by earlier leasing, offsetting any declines in bonuses that may be due to areawide leasing.

The analysis focuses on two types of comparisons. The results of the areawide and focused-on-promising-acreage lease sales of 1983 through 1985 are compared to the results of tract selection sales in prior years. This analysis shows how the pace of leasing and investment was influenced by sale procedures, world oil prices and previous leasing. In addition, comparisons are made of the likely effects, in the 1986-1991 era, of restricted lease offerings, such as those that resulted from tract selection procedures, and more rapid lease offerings, such as those under areawide or focusing procedures.

II. A Framework for Assessing Effects on Investments and Economic Benefits

One way to approach the analysis of OCS oil and gas investments and the resulting benefits to the economy is to develop a picture of how investments would be made over an extended period of time if there were no restrictions on OCS leasing and the availability of investment opportunities. If there were no restrictions, environmental damages or adverse onshore impacts and the leasing program operated in a fashion that made acreage available whenever it was seen as a good investment, then the resulting path of investments would reflect the response of oil and gas companies to the conditions that determine the economic attractiveness of OCS prospects. OCS investments would be determined by the same processes that govern investments throughout the economy, including those for oil and gas development on private lands. The economy would benefit from the returns on such OCS investments just as it does from investments in other sectors.

The conditions that affect the payoffs from OCS investments include the economic characteristics of OCS oil and gas deposits, the state of geological and geophysical knowledge, and economic conditions and expectations (particularly regarding future oil and gas prices). As discussed in Appendix F, prospects in which oil and gas may be discovered vary substantially, particularly in those characteristics that affect the cost of finding and producing oil and gas. For a given set of expectations about future prices, a lower cost prospect has higher expected economic benefits and higher payoffs from the investments needed to explore and develop the prospect. Some prospects have costs so high that investments are not worthwhile until prices are expected to be higher or until the chance of finding oil has been increased by additional geological and geophysical knowledge.

If one or both of these developments is expected to proceed as time passes, then the OCS can be described as an inventory of ripening investment opportunities. As time passes, increasing prices or emerging resource

knowledge gradually make some prospects more attractive for investment. In general, the lowest cost, most easily found prospects become attractive earliest. (In the case of Gulf of Mexico offshore oil, this occurred in the late 1940s and 1950s.) As time passes, exploration reveals the location of most of the large, low cost deposits. Higher cost prospects become attractive for investment as oil prices increase or technology reduces costs.

In this picture of the OCS, firms are constantly reviewing the prospects for investment so that any major event, such as the OPEC price increases of 1974 or 1979, that rapidly increases the number of good investment opportunities brings forth a period of greater investment until the freshly ripened opportunities have all been harvested. Similarly, when events reduce the attractiveness of the remaining OCS investment opportunities, the rate of investment is reduced.

In actuality, of course, a variety of administrative, political and legal restrictions have been placed on the availability of OCS prospects for investment. Setting aside the question of whether such restrictions are warranted because of the potential environmental and onshore effects of OCS oil and gas development, it is possible to examine their consequences for investment.

If OCS tracts are not available for leasing and investment when they become attractive, the inventory of unleased acreage will come to contain more good prospects and their value will increase. (As Appendix F shows, most gains of this type are not sufficient to warrant the delays in investment.) The more restrictive the leasing program, and the longer the period of restriction while oil prices and price expectations increase and geological knowledge of good prospects evolves, the greater would become the number and the value of unleased prospects attractive for investment. Many unleased tracts would have costs substantially less than those of the most costly tracts that were economic to develop at that time. Leasing of the better tracts from such an inventory would tend to yield relatively high bids.

Once a sizable inventory of valuable unleased prospects has accumulated, the rates of leasing and investment that could result from unrestricted access are substantial, at least until the inventory has been drawn down. Any institutional rigidities in the capacity to expand investments would tend to temper the response, stretching the draw-down period over a longer time. Eventually, however, the inventory would be depleted of most of the highly valuable prospects that had become over-ripe for investment. Continued unrestricted leasing would then result in more moderate levels of leasing and exploration with periods of expansion and recession in response to changes in economic conditions and expectations.

It is worth noting that the inventory buildup caused by restrictive leasing in mature areas like the Gulf of Mexico would differ from that in frontier areas. As any area matures by undergoing extensive exploration, the early investments tend to lease and find the relatively few large, low cost deposits. As shown in Appendix F, the resource potential remaining in an area that has undergone substantial exploration tends to be located in more numerous smaller prospects that yield fewer economies of scale. Restriction of leasing in a mature area would thus tend to build up an inventory of many moderate to small prospects along with a few larger prospects at the high cost

margins of the area where exploration has not yet occurred. The eventual leasing of this inventory of good prospects could involve substantial acreage, most of it with much lower yield potential than that leased earlier. While some tracts would have substantial value, many more would have modest value.

In contrast, a frontier area, which because of its high cost has not been worth exploration investments until substantial price increases occurred, would tend to build up an inventory of relatively few large prospects if leasing did not make acreage available as soon as it became ripe. The few large prospects could hold the potential for a substantial amount of production from a relatively small amount of acreage. Although such an area may also contain many smaller prospects, costs are so high that even after years of delay in initial leasing, prices may not be sufficient to make them ripe for investment.

Thus, unrestricted leasing after a period of restriction would be expected to yield far different results in a mature area than in a frontier area. In a mature area, the amount of acreage leased and the rate of investment in exploration would tend to be quite substantial. The potential resource yield per acre and its average economic value per acre might be lower than during a period when mostly higher value tracts were offered. In comparison, unrestricted offerings in a frontier area would tend to lease much less acreage, but it would tend to have a high resource yield per acre. Its economic value could be substantial in the largest prospects and moderate in large prospects just ripe for investment.

The basic concept of an inventory of ripening investment opportunities from which OCS leasing occurs can also provide a framework for analyzing the effects of the pace of leasing on the benefits realized by the economy. The ripening of investment opportunities occurs because increasing oil prices, decreasing geologic risk or increasing resource potential make the returns on investment grow. These private returns are paralleled by the benefits to the economy as a whole. The economic benefits expected from a tract, measured in terms of net economic value as defined in Appendix F, increase as oil prices increase, risk decreases or resource potential increases. While the long term expectation of increasing oil prices implies a long term growth in the net economic value of OCS deposits, the timing of development also affects the overall benefit realized by the economy. As explained in Appendix F, this effect is measured by calculating the present values of benefits expected to be realized in various future times. Discounting future benefits to present value accounts for the fact that at an interest rate of, say, 8%, a dollar received 10 years from the present is worth $0.46 today while a dollar received 20 years from the present is worth $0.22 today.

This principle can be used to examine the consequences of different rates of leasing for the overall benefits which the economy realizes from development of OCS oil and gas deposits. For example, if leasing is restricted during a period of rapid growth in the value of OCS prospects, the inventory of unleased acreage will come to contain more tracts with higher net economic value. In particular, the amount of leasable resources (as defined in Appendix F) will increase and there would also be an increase in the number of deposits that would experience a loss in total economic benefits if their development were delayed. In general, earlier leasing and development of such tracts will increase the benefit to the economy, measured in present value terms.

Even with unrestricted access to the inventory of unleased acreage, the investment process does not immediately lease and explore all of the tracts that actually contain oil and gas. The process of searching through a sizeable inventory of unleased acreage to identify prospects that are worth leasing and exploring creates sequence in the leasing of tracts, spreading the investments needed to locate economical oil and gas deposits over many years. The economic benefits realized from this search process can be increased if the search is conducted at a more rapid pace.

The temporary increase in the rate of searching for oil and gas that occurs when a substantial inventory of unexplored prospects becomes available causes greater economic benefit for two reasons. The first is the earlier discovery and development of the economical oil and gas on the tracts explored during the period of acceleration. The second is that exploration during the period of acceleration provides earlier information for locating prospects that occur toward the end of the search sequence. To illustrate this effect it is useful to picture a search in which 1,000 locations must be examined sequentially. If the search proceeds at the rate of 3 locations per month, it will take nearly 28 years to complete the search. Any prize in the last place to be searched is 28 years away. However, if the search rate is 10 locations per month for the first 5 years and then 3 per month until the search is complete, then the prize in the last location can be found after 16 years instead of 28 years. Although the sequence in the search for oil and gas is not fixed as in this example, temporary increases in the rate of leasing can be expected to have similar effects on the timing of the discovery of oil and gas prizes and the realization of their benefits to the economy. Such effects can be evaluated using present value calculations. Section III provides the results of such an analysis.

III. Consequences of the Pace of Leasing for Investments and Economic Benefits

One of the key concerns expressed about the pace of OCS leasing is whether the larger and more rapid lease sales would bring about changes in the rate of investment in OCS exploration and development and the economic benefits from production of less costly oil and gas resources. Areawide leasing has been criticized for its inability to overcome capital limitations or change the timing of resource development.

Limitations on the capital available for OCS investments could result if firms active on the OCS could not or would not increase the budget allocated to lease acquisition and exploration and if other firms could not enter the offshore market. Capital limitations would be evidenced by a limited increase in the rate of seismic data collection, lease acquisition and exploratory drilling despite the substantially expanded opportunities provided by accelerated leasing. Capital limitations would be of concern in the formulation of the third 5-Year leasing program if there was evidence that they would not ease over time and that the number of new prospects that would be made available by the future leasing program would outpace the capital that could be made available. One response to capital limitations would be to restrict the amount of acreage offered for lease by using procedures such as tract selection or focusing on promising acreage. Other possibilities include policies to promote the flow of capital into oil and gas exploration or to reduce the capital required to participate in leasing and exploration.

Areawide leasing was adopted in the 1982 5-Year Leasing Program in order to allow more rapid exploration, discovery and development of OCS oil and gas resources. This decision was based on the evidence that the government's inventory of unleased acreage contained numerous oil and gas prospects of sufficiently high value that they would be economical to develop and produce without waiting for higher oil and gas prices. As Appendix F describes, many such prospects had been economical for some years. Further delays in their development and production would have resulted in lower economic benefits to the nation's economy. There were also prospects, however, that were barely economical to explore or develop. If the 1982 inventory of unleased acreage had been comprised primarily of a moderate number of such low value prospects, then the rate of investment in exploration and development would not have been much affected by the choice of tract selection or areawide leasing. Both would have made available the limited number of prospects that were economic at each point in the 5-year period. If, on the other hand, the unleased inventory in 1983, when areawide sales began, contained a substantial number of good investment prospects, then the rate of investment could be increased substantially by areawide sales. Thus the amount of acreage leased and the bonuses paid can indicate the character of the inventory as areawide leasing began.

To determine whether the shift from tract selection to areawide procedures caused the desired expansion in leasing and investment in exploration, it is useful to examine data for leasing, seismic data collection, and exploratory drilling in an area in which there is substantial data under both procedures. Leasing in the Gulf of Mexico provides the best data for such an analysis. Since there has been insufficient time for lessees to complete the sequence of discoveries and development, it is not possible to determine empirically whether development investments have increased. It is possible, however, to assess the relationship between exploratory drilling investments and the expected timing of development investments. The cost of capital limits the number of years that firms will be willing to invest in exploratory drilling in advance of the time they expect to be able to develop profitably the oil and gas deposits they expect to find. Similarly, because the leases are limited to 5 years and in deep water, 10 years, firms will not acquire leases that they do not expect to be economical to explore within these time frames.

A. Lease Availability and Acquisition

Table 1 shows the acres offered, the acres leased and the cash bonuses collected in each year, separating the tract selection and areawide sales as of May 1983. In the Central and Western Gulf of Mexico, leasing proceeded under the tract selection procedures at a rate of about 1 million acres per year during the late 1970s and early 1980s. Almost twice as much acreage was offered, about 1.7 million acres per year. Despite the nomination and tract selection process, only half of the acreage selected as promising 20-some months prior to each sale proved worth bidding upon after further evaluation. In 1983, areawide leasing expanded the acreage offered in the Gulf of Mexico by a factor of 35. Acreage leased expanded from 1 million acres per year to about 5 million acres. This shows a very substantial increase in the amount of acreage evaluated, bid upon and transferred into the lease portfolios of offshore firms. It confirms the buildup of a sizeable inventory of good prospects and shows a substantial rate of lease acquisition in response to their availability. Beginning in 1984, the amount of acreage

Table 1

Rate of Lease Acquisition

(acreage in millions, bonuses in billions of dollars)

	C & W Gulf of Mexico			Other Areas		
Year	Acres Offered	Acres Leased	Total Bonuses	Acres Offered	Acres Leased	Total Bonuses
1972	1.0	.8	2.3			
1973	1.7	.5	1.6	.8	.5	1.5
1974	5.0	1.8	5.1			
1975	6.0	1.3	.8	1.3	.3	.4
1976	1.0	.4	.6	1.9	.9	1.7
1977	1.1	.6	1.2	.8	.5	.4
1978	1.8	1.0	1.7	1.3	.2	.1
1979	1.2	.8	3.2	2.3	.9	1.9
1980	1.4	1.0	4.1	1.2	.2	.1
1981	2.2	1.3	3.9	5.5	.9	2.6
1982	1.9	.9	1.8	5.6	1.0	2.1
1983						
TS	.7	.1	-	5.1	.9	.7
AW	70.5	5.3	4.9	43.8	.3	.1
1984	64.7	4.9	2.1	89.5	3.3	1.8
1985	51.2	3.2	1.5	*	*	*

* The only sale held outside the Central and Western Gulf of Mexico areas in 1985 occurred late in the year. Leasing results were not available when this appendix was completed.

offered in the central and western Gulf of Mexico lease sales decreased, both because of previous leasing and the procedures to focus on promising acreage. The rate of lease acquisition also declined to 3.2 million acres in 1985.

In all other areas combined, lease offerings averaged about 3 million acres per year over the 1978-1982 period with leasing at about 0.7 million acres per year. Areawide leasing expanded the acreage offered in other areas to about 43.8 million acres in 1983 and 89.5 million 1984, with leasing of a total of 3.6 million acres. As expected, the amount of valuable acreage built up in the Government's inventory was less in these mostly frontier areas.

The extent of the capital investment made by firms acquiring leases can be judged by examining the bonuses paid. Under tract selection procedures, bonuses for Gulf of Mexico leases averaged about $3 billion per year in the late 1970s and early 1980s, though they had dropped to half their 1980 peak by 1982. Under areawide procedures, total bonuses paid increased to nearly $5 billion and then fell off to $2.1 billion in 1984 and $1.5 million in 1985. It is worth noting that the substantial increase occurred in 1983, a year in which oil industry net income, the major source of capital, had dropped 27 percent from peak levels of $29.3 billion in 1980 to $21.3 billion.[1] Total bonuses in the first round of areawide sales were nearly equal to the total net economic value of the resources estimated to be leased in Appendix 2 of the March 1982 SID for the 1982 5-Year Leasing Program. Because bonuses paid are estimated to be about 40 percent of net economic value in the Gulf of Mexico, this implies that industry leased about 2.5 times as much in 1983 as had been estimated. Thus the investment response was greater than expected at the time the 1982 program was approved.

Analysis by the MMS estimates that about 10 percent of the unleased undiscovered recoverable resource thought to be in the Gulf of Mexico areas in 1982 was leased in 1983 and another 7 percent was leased in 1984. This is about three times the portion that was estimated to be leased, which is fairly consistent with the estimate derived by comparing bonuses to net economic value. Evidently, the petroleum industry was willing to invest more in the acquisition of leases than had been anticipated.

B. Inventory Buildup and Depletion

The lease sales in the Gulf of Mexico provide a good basis for examining trends in the value of acreage being leased. Since leasing tends to focus on the most valuable acreage, particularly if the acreage offered is limited, the average value can suggest the extent to which the inventory of unleased tracts has appreciated. In general, it is reasonable to conclude that the greater the value of the tracts leased, the greater has been the extent of appreciation that has occurred before the acreage was offered. Table 2 shows the trends in the average of high bids on tracts leased in each year starting in 1970.

[1]Data for the top 24 oil companies from the American Petroleum Institute, October 1984.

Table 2
Trends in Average of High Bonus Bids for Leased Tracts
(dollars per acre)

	Gulf of Mexico		California		Atlantic		Alaska	
Year	Sale	Average Bonus Per Acre	Sale	Average Bonus Per Acre	Sale	Average Bonus Per Acre	Sale	Average Bonus Per Acre
1970	21	2,190						
	22	1,530						
1971	23	2,587						
1972	24	2,018						
	25	3,108						
1973	26	2,908						
	32	3,072						
1974	33	4,968						
	34	2,605						
	S1	302						
	36	2,248						
1975	37	438	35	1,346				
	38	572						
	38A	485						
1976	41	1,091			40	2,130	39	1,369
	44	2,129						
1977	47	1,933					CI	805
1978	45	1,672			43	412		
	65	304						
	51	2,113						
1979	58	3,189	48	1,987	49	180	BF	5,800
	58A	4,539			42	2,277		
1980	A62	4,853					55	551
	62	3,699						
1981	A66	3,312	53	6,388	46	1,218	60	60
	66	2,446			59	1,115		
1982	67	2,022	68	669			71	3,101
	69(1)	2,166						
1983	69(2)	646	73	366	76	325	57	946
	72	1,090			78	213	70	780
	74	668						
1984	79	346	80	543			83	609
	81	581					87	722
	84	433						
1985	98	520						
	102	334						

The average of high bids is not a perfect indicator of the economic value of the tracts leased. If changes in competition allow firms to bid a smaller fraction of the value they see in a tract and still win the lease, then the average of high bids will decline relative to average economic value. The average of high bids is also subject to inflation effects which could mask changes in real economic value. Isolating the various factors that affect bid levels is a complex analytical task. Such a study is provided in Section V.

The early history of leasing in the Gulf of Mexico shows the average of high bonus bids was generally less than $500 per acre, except for sales of drainage tracts for which nearby drilling had confirmed the presence of a commercial deposit. None of the wildcat lease sales of the 1950s and 1960s exceeded $1,000 per acre, despite the fact that exploratory drilling during that time yielded discoveries containing most of the oil and gas that has been discovered to date.

In the 1970s however, the average of high bids increased as OPEC began to exert its price setting power. The early 1970s saw the average of high bids in the $2,000 per acre range, increasing to nearly $5,000 per acre in 1974. Efforts to increase OCS leasing yielded relatively larger offerings in the Gulf of Mexico, reaching 5 million acres in 1974 and 6 million acres in 1975. As a result, a total of 3 million acres were leased in 1974 and 1975 combined. The average of high bids declined sharply to about $500 per acre in 1975.

The 1974-1975 decline in the average of high bids could have been caused by dilution of competition, by leasing more moderately valued tracts along with the higher valued tracts, or by depletion of the unleased inventory through leasing of the limited number of prospects that had been made highly valuable by the OPEC price increases. The trend in the average of high bids in the next 3 years, 1976-1978, gives evidence that the inventory had been substantially depleted of the highly valuable tracts that had emerged early in 1974. The average stayed substantially below the 1974 $5000 per acre peak during the 1976 through 1978 period when the acreage offered averaged about 1.3 million acres per year.

Thus, when lease offerings had returned to their pre-1973 size and, presumably, to their pre-1973 levels of competition, the better tracts being leased were similar in value to those being leased at the turn of the decade. The increased pace of leasing in 1974 and 1975 allowed acquisition of the valuable prospects that resulted from the appreciation effect of higher oil prices.

The trend in the average of high bids indicates a second period of inventory buildup during the 1978-1980 period. Gulf of Mexico lease sales during this time offered an average of 1.5 million acres per year. The average of high bids peaked in 1980 at nearly $5,000 per acre just as oil prices and oil price expectations peaked. During 1981 and 1982, world oil prices and oil price expectations declined. Gulf of Mexico lease sales increased slightly to about 2 million acres per year offered and 1 million leased while the average of high bids declined gradually to about $2,000 per acre. Thus the 5 years before areawide leasing saw about 5 million acres leased while the average rose from about $2,000 per acre to nearly $5,000 per acre and then declined back to $2,000 per acre.

The average high bid for an OCS sale can be strongly influenced by a few very high value tracts, particularly in the smaller, tract selection sales. While the average would indicate the influence of the best tracts leased in each sale, the chance inclusion of very high value tracts in some sales and not in others that can be caused by emerging exploration results can make the average high bid a less useful measure of trends. (This is the case, for example, in Sale 53 which had an average bonus of $6,388 per acre.)

The median of high bids is less subject to the extremely high values of a few tracts. (The median is the middle value in a ranked list of values.) The medians of high bids for Gulf of Mexico sales since 1979 are shown in Table 3. The peak median high bid occurred in 1979. Significant decreases in the median high bid occurred from 1979 to 1982 as well as in 1983 through 1985.

Estimates made in late 1981 and early 1982 for the second 5-year leasing program indicated unleased oil and gas resources in the Central and Western Gulf of Mexico of 15.6 billion BOE and a net economic value of about $200 billion. These estimates, together with the relatively high average bids during the previous 4 years, suggested that the Government had built up a substantial inventory of tracts worthy of investment.

The extent of leasing in 1983 through 1985, despite significant further decreases in world oil prices and price expectations, confirms the existence of a substantial unleased inventory in 1982. The areawide lease sales in the Central and Western Gulf leased over 13 million acres in these 3 years. This is more than the total amount of Gulf of Mexico acreage leased over the previous 15 years. Since lease values would not have appreciated, except because of new geological knowledge, during the price declines between 1981 and 1985, it is clear that most of the acreage leased in 1983 was already ripe for investment in 1982.

The evidence of buildup in the unleased inventory in other OCS areas is not as dramatic as it was in the Gulf of Mexico. The increase in acreage leased is not great though it is significant in value. Early frontier area sales in the Atlantic and Alaska areas yielded average high bids substantially higher than sales at a comparable point in the history of exploration in the Gulf of Mexico. Lease sales 40 and 42 in the Mid- and North Atlantic areas yielded average high bids of more than $2,000 per acre. The first sales in the Beaufort Sea had averages of $5,000 and $3,100 per acre. Values so much higher than the $500 per acre level of early Gulf of Mexico leases are strong evidence that the best prospects in the Government's inventory of tracts in these frontier areas had appreciated substantially in value before they were offered.

Interpretation of trends in bids is complicated by the fact that an average is sensitive to the mixture of tracts sold. Relatively small offerings composed of tracts of sufficiently good prospects to have been nominated by a number of firms, would yield higher averages than much larger sales from the same inventory of tracts even if the bids were not affected by the size of the offering. A larger sale with more low value tracts added into the total along with the fewer high value tracts that would have been leased in a smaller sale would have a lower average bonus. The average of high bids would only provide strong evidence of an inventory buildup for sales of comparable size and selection. With the exception of the larger Gulf of Mexico sales in 1974 and 1975, the lease sales of the 1970s were comparable in this respect.

Table 3

Trends in the Median of High Bonus Bids for Leased Tracts

(dollars per acre)

Central and Western Gulf of Mexico Sales

Year	Sale	Bid Per Acre
1979	58	1,561
	58A	2,529
1980	A62	1,982
	62	2,231
1981	A66	1,726
	66	958
1982	67	844
	69(1)	775
1983	72	473
	74	390
1984	81	282
	84	267
1985	98	241
	102	212

C. Exploration Investments in the Gulf of Mexico

Since areawide leasing was initiated, seven such lease sales held through 1985 have been held in the Gulf of Mexico. Approximately 2 years have passed since OCS Lease Sale 72, the first areawide Central Gulf of Mexico lease sale was held on May 25, 1983. Subsequent areawide and focused lease sales were held in the Western Gulf of Mexico on August 24, 1983, July 18, 1984, and August 14, 1985, and in the Eastern Gulf of Mexico on January 5, 1984, and in the Central Gulf on April 24, 1984, and May 22, 1985.

The exploration process begins with the collection of geological and geophysical data using primarily seismic techniques. These data are used to identify unleased tracts with good prospects for the discovery of oil and gas. Seismic data collection in the Gulf of Mexico had been occurring typically at the rate of about 150,000 miles of seismic data per year during the 1978-1981 period. In 1982, in anticipation of the areawide lease sales in 1983, it rose to nearly 380,000 miles. In 1983, it was over 295,000 miles. These substantial investments in data collection were made in an area that was already among the most intensively studied in the world. It tends to show that the oil industry believed in 1982 and 1983, that there was an extensive inventory of acreage worth considering.

Drilling and discovery data are now available for leases issued in the Central and Western Gulf, Lease Sales 72, 81, 98 and 74, 84, 102 respectively, as a result of the areawide sales. These data provide a comparison of the exploration activity on leases issued for areawide and tract selection sales in the Central and Western Gulf.

One difficulty in making comparisons between tract selection and areawide sales is in the variation in the time available for drilling activities. The data presented in the analysis and tables below are current as of November 1, 1985. It is obvious that leases issued from Lease Sale 58, held July 3, 1979, have been in force for a period of more than 5 years and it may be expected that more activity would occur on those leases than on those issued in 1983.

In order to provide some basis of comparison for leases with different time spans between lease issuance and the cutoff date of November 1, 1985, the following procedure was adopted. All data on tracts showing progress in drilling and discovery were compiled for a specific lease sale and a percentage of the total number of tracts in the sale showing progress was computed. Each of these percentages was divided by the period of time between the lease sale and the cutoff date, yielding an average annual percentage. Comparison of the average annual percentages provide an approximate indication of the differences that may exist between tract selection sales and areawide sales, after removing some of the differences that are due to the longer period of exploration and development time available to the tract selection sales.

Three comparison tables were prepared. First, a comparison of the tracts on which drilling has taken place as a percentage of tracts leased for Gulf of Mexico sales from 1979 through 1985. Second, a comparison of new productive leases as a percentage of tracts drilled for the same areas and same time period. Third, a comparison of tracts classified as new field discoveries as a percentage of tracts drilled for the same areas and same time period.

Table 4 contains a summary of exploratory drilling activity by both individual sales and on an annual basis. All of the sales between 1979 and 1982 were tract selection sales and the 1983 sales were areawide. The annual average percentages indicate that, in the Gulf of Mexico, lessees tend to drill each year approximately 16 percent of the leases acquired in a given lease sale until approximately 85 percent of the leases have been drilled. The remainder of the acquired leases remain undrilled. The average annual percentage for areawide Sales 72 and 74 are in accord with the similar averages pertaining to the tract selection sales. The Sale 81 and 84 average is somewhat less while the Sale 98 and 105 average is less than six percent; however, since relatively little drilling can occur in the first few months of a lease, this average reflects the short period in which Sale 98 and 102 leases have been active as of the time of this data. In addition sale 81, 84, 98 and 102 leases were issued about 2.5 months after the sale while the other leases were issued within a couple of weeks of a sale. The Sale 69 tracts show a somewhat greater than average rate of exploration. This may be due to the above average potential of those tracts. It may also be the result of drilling efforts in preparation for the areawide sales planned for 1983 and 1984.

The rate of progress in drilling on leases issued in areawide sales thus appears to be about the same as the long run rate of drilling on leases from tract selection sales despite the fact that almost 10 times as many tracts were leased. The increased acquisition of leases in Sales 72 and 74 has been followed by an increased investment in exploratory drilling. The increase in the pace of investment is particularly apparent in the yearly data with about three times as many 1983 tracts drilled as have been drilled, on average, on tracts leased in 1979-1982 sales, despite the shorter time since the 1983 lease sales.

Table 5 contains a summary of new productive leases as a percentage of leases drilled. The percentage of tracts drilled that are productive is lower for areawide sales than for tract selection sales. One reason is that even when oil or gas is found on a tract it is not necessarily the first well that is productive. Later wells on a tract may prove productive and the percentage will increase. In fact, the percentage did increase in the second year of exploration on leases from sales 72 and 74. Another reason is that there were more marginal tracts leased in the areawide sales and the percentage is expected to be lower.

Table 6 contains a summary of new field discoveries as a percentage of leases drilled. The areawide sales in 1983 have a higher rate of new field discoveries than some of the previous tract selection sales. In fact, the new field discoveries from the 1983 sales exceeds the new field discoveries from sales in 1980-1982.

The data shown on these tables cover a period of relatively abrupt changes in the market prices for oil and gas, as well as expectations regarding future prices, which may be reflected in drilling and production activities. Crude oil prices and expectations increased from 1979 through 1981 and subsequently declined, and natural gas prices came under downward pressure early in 1983. These trends would tend to dampen drilling investments in 1982 and 1983. Thus, the increased rate of drilling on the tracts leased in 1983 areawide sales is despite, rather than because of, the trends in oil prices.

Table 4
Gulf of Mexico Exploratory Drilling Activity

A. By Sale

Sale	Date	Tracts Leased	Tracts Drilled	Percent of Leased Tracts Drilled	Years Active[1]	Average Annual Percentage (Col.5/Col.6)
58	07/31/79	81	77	95.1	6.3	15.1
58A	11/27/79	90	75	83.3	5.9	14.1
A62	09/30/80	116	96	82.8	5.1	16.2
62	11/18/80	67	50	74.6	4.9	15.2
A66	07/21/81	156	94	60.3	4.2	14.4
66	10/20/81	102	54	52.9	4.1	12.9
67	02/09/82	115	57	49.6	3.8	13.1
69	11/17/82	56	34	60.7	3.0	20.2
69A[2]	03/08/83	11	7	63.6	2.7	23.6
72	05/25/83	623	279	44.8	2.4	18.7
74	08/24/83	406	155	38.2	2.2	17.4
79	01/05/84	156	12	7.7	1.8	4.3[5]
81	04/24/84	453	89	19.6	1.5	13.1
84	07/18/84	361	53	14.7	1.3	11.3
98	05/22/85	409	9	2.2	0.4	5.5
102	08/14/85	195	0	-	0.2	-

B. By Year

Year	Sales	Tracts Leased	Tracts Drilled	Percent of Leased Tracts Drilled	Average Years Active[4]	Average Annual Percentage (Col.5/Col.6)
1979	(58,58A)	171	152	88.9	6.1	14.6
1980	(A62,62)	183	146	79.6	5.0	16.0
1981	(A66,66)	258	148	57.4	4.2	13.7
1982[2]	(67,69,69A)	182	98	53.8	3.4	15.8
1983[3]	(72,74,79)	1185	446	37.6	2.3	16.3
1984	(81,84)	814	142	17.4	1.5	11.6
1985	(98,102)	604	9	1.5	0.3	5.0

[1]Number of years that leases from sale have been in effect as of 11/1/85 when drilling data was compiled.

[2]Sale 69A, a tract selection sale, was held early in 1983 but is included with the major portion of Sale 69.

[3]Sale 79, an areawide sale, was planned for 1983, but was delayed until early 1984. It is included herein with the other 1983 sales.

[4]Average among sales weighted by number of tracts drilled.

[5]Drilling rates have been artificially depressed by constraints on the pace of permit approvals due to Defense Department requirements.

Table 5

Gulf of Mexico New Productive Leases

A. By Sale

Sale	Tracts Drilled	Productive Tracts	Percent of Drilled Tracts That Are Productive	Years Active[1]	Average Annual Percentage (Col.4/Col.5)
58	77	42	55.0	6.3	8.7
58A	75	33	44.0	5.9	7.4
A62	96	49	51.0	5.1	10.0
62	50	19	38.0	4.9	7.6
A66	94	44	46.8	4.2	11.1
66	54	25	46.3	4.1	11.3
67	57	26	45.6	3.8	12.0
69	34	10	29.4	3.0	9.8
69A	7	1	14.3	2.7	5.3
72	279	99	35.5	2.4	14.8
74	155	49	31.6	2.2	14.4
79	12	-	-	1.8	-
81	89	27	30.3	1.5	20.2
84	53	4	7.5	1.3	5.8
98	9	0	-	0.4	-
102	-	-	-	0.2	-

B. By Year

Year	Sales	Tracts Drilled	Productive Tracts	Percent of Drilled Tracts That Are Productive	Average Years Active[2]	Average Annual Percentage (Col.5/Col.6)
1979	(58,58A)	152	75	49.3	6.1	8.1
1980	(A62,62)	146	68	46.6	5.0	9.3
1981	(A66,66)	148	69	46.6	4.2	11.1
1982	(67,69,69A)	98	37	37.8	3.4	11.1
1983	(72,74,79)	446	148	33.2	2.3	14.4
1984	(81,84)	142	31	21.8	1.5	14.5
1985	(98,102)	9	0	-	0.3	-

[1]Number of years that leases from sale have been in effect as of 11/1/85.
[2]Average among sales weighted by number of tracts drilled.

Table 6

Gulf of Mexico New Field Discoveries

A. By Sale

Sale	Date	Tracts Drilled	New Field Discoveries	Percentage of Drilled Tracts with Discoveries	Years Active[1]	Average Annual Percentage (Col.5/Col.6)
58	07/03/79	77	13	16.9	6.3	2.7
58A	11/27/79	75	11	14.7	5.9	2.5
A62	09/30/80	96	11	11.5	5.1	2.3
62	11/18/80	50	12	24.0	4.9	4.9
A66	07/21/81	94	21	22.3	4.2	5.3
66	10/20/81	54	13	24.1	4.1	5.9
67	02/09/82	57	17	29.8	3.8	7.8
69	11/17/82	34	4	11.8	3.0	3.9
69A	03/08/83	7	1	14.3	2.7	5.3
72	05/25/83	279	59	21.1	2.4	8.8
74	08/24/83	155	26	16.8	2.2	7.6
79	01/05/84	12	0	-	1.8	0
81	04/24/84	89	13	14.6	1.5	9.7
84	07/18/84	53	3	5.7	1.3	4.4
98	05/22/85	9	0	0	0.4	-
102	08/14/85	0	0	0	0.2	-

B. By Year

Year	Sales	Tracts Drilled	New Field Disc.	Percentage of Drilled Tracts with Discoveries	Average Years Active[2]	Average Annual Percentage
1979	(58,58A)	152	24	15.8	6.3	2.5
1980	(A62,62)	146	23	15.8	5.2	3.0
1981	(A66,66)	148	34	23.0	4.4	5.2
1982	(67,69,69A)	98	22	22.4	3.6	6.2
1983	(72,74,79)	446	85	19.1	2.5	7.6
1984	(81,84)	142	16	11.3	1.7	6.6
1985	(98,102)	9	0	-	0.3	-

[1]Number of years that leases from sale have been in effect as of 11/1/85.
[2]Average among sales weighted by number of tracts drilled.

The average annual percentages on Tables 4, 5 and 6 are somewhat affected by the differences in the ages of the leases from each sale. In the tract selection sales, 25-35 percent of the tracts were drilled in the first year after issuance of a lease. In the second year after issuance, 35-65 percent of the tracts in the tract selection sales were drilled. In sale 72, 31 percent of the tracts were drilled 23 months after the sale. In sale 74, 27 percent of the tracts were drilled 19 months after the sale. The average annual percentages therefore somewhat overstate the drilling from areawide sales relative to tract selection sales. Comparisons of these tables with similar tables prepared with data through November 1, 1984, however lead to the conclusion that these variations are not significant.

This comparison of postlease exploration activity suggests that areawide leasing has had a favorable effect on investment. Although leases resulting from areawide lease Sales 72 and 74 have been in existence only about two years, drilling activity, based on number of leases drilled, seems to be proceeding at a high rate. At the time of the analysis (November 1985), Sale 72 had been held less than 2.5 years earlier, and more Sale 72 leases had been drilled than leases from any other sale studied. Similarly, more Sale 74 leases had been drilled in their first year than in the any period of any tract selection lease sale studied.

The current level of investment in exploratory drilling can also be measured by the number of drilling rigs active. In the Gulf of Mexico, there were almost 200 rigs active in late 1984 and in late 1985 about 150 rigs were active. This is an increase from a low of about 120 during the summer of 1983 as the first areawide sales were occurring. This is a record level of drilling activity in the Gulf of Mexico and is counter to the trend of world oil prices in 1983 and through 1985.

Lessees' intentions to invest in exploratory drilling can be gauged by the exploration plans they have filed to gain the necessary permits from the MMS. During the period of 1978-1982, Gulf of Mexico exploration plans were filed at an average rate of about 450 per year. Filings in 1983 were over 500 and in 1984 they reached 800. This demonstrates the likelihood that investments in exploratory drilling will continue in 1985 at a rate similar to or greater than the rate in 1984.

D. Effects on Economic Benefits

The investments evident in lease acquisition and exploratory drilling indicate the lessees' expectations about potential returns. The framework developed in Section II can also be used to analyze the effects of different leasing rates on the total economic benefits realized by the economy. Figures 1 and 2 show the results of an analysis which compares the economic benefits from leasing in the Central and Western Gulf of Mexico under rapid leasing typical of the areawide and focused-on-promising-acreage approaches on one hand and slower leasing of 200 tracts per year typical of the 1976-1982 era tract selection lease sales on the other. Actual leasing results were used for 1982-1985. Projections of leasing in 1986 and under the Base Schedule Option (SID, p. 103) for 1987-1991 were used. Leasing of the currently leasable resources remaining to be leased in 1992 was assumed to occur at the rate of 200 tracts per year containing a total of 400 million barrels (risked).

This comparison is not intended to be a forecast of leasing under tract selection procedures. Nor is it meant to be a forecast of leasing beyond the 1987-1991 program. It's purpose is to illustrate the substantial effects on the economy that can result from more rapid leasing of those prospects currently ripe for investment, as are the currently leasable resources in the Central and Western Gulf of Mexico.

Figure 1 shows the cumulative economic benefits achieved by leasing in the Central and Western Gulf of Mexico starting in 1982, leasing the same resources at different rates. The economy benefits by about $36 billion more under the more rapid leasing program. The economy is ahead under more rapid leasing in every year.

Figure 2 shows the results of this analysis in a form that allows comparison of the economic benefits realized from the sets of tracts leased under the different programs. For the 3,144 tracts leased under the 1982-1986 period, the two bars show the total economic benefits under the leasing program actually implemented compared to the leasing of tracts having the same economic value at 200 tracts per year over the 1982-1997 period. The more rapid program is expected to achieve $18 billion more in economic benefits from development of the resources leased than would be expected from the 200 tract per year program.

Similarly, for the 2,008 tracts assumed to be leased in the 1987-1991 program, the two bars in Figure 2 show the total economic benefits from leasing in those five years as compared with the benefits that would result if the same tracts were leased in the 1997-2007 period under a 200 tract per year program. Note that because of the slower leasing rate since 1983, the leasing of the remaining tracts begins 10 years later under the 200 tract per year program. The more rapid program yields $12 billion more in economic benefits.

The bars in Figure 2 for the currently leasable resources that remain to be leased in 1992 after the end of the 1987-1991 program show the economic benefits from leasing 2,641 tracts at 200 tracts per year from 1992 through 2005 under the more rapid areawide type program compared to the benefits from leasing at 200 tracts per year from 2,007 through 2,021 under the slower program. Slower leasing of the 5,152 tracts leased starting in 1982 delays the leasing and the realization of the benefits from the remaining tracts by 13 years. The economy gains about $6 billion from the faster program. It is important to note that this $6 billion difference results, not from more rapid leasing of the 2,641 remaining tracts but from the fact that they can be leased and developed sooner because of the information generated by earlier leasing and exploration of the preceding tracts.

Table 7 shows the leasing schedules and associated present values of the two options for the cases illustrated in Figures 1 and 2. The assumptions for this case are a $24 per barrel price of oil in 1987, a one percent per year price growth thereafter, and a real discount rate of eight percent.

Figure 1
CUMULATIVE ECONOMIC BENEFITS OF
RAPID AND SLOWER LEASING PROGRAMS
CENTRAL AND WESTERN GULF OF MEXICO
(Base Case)

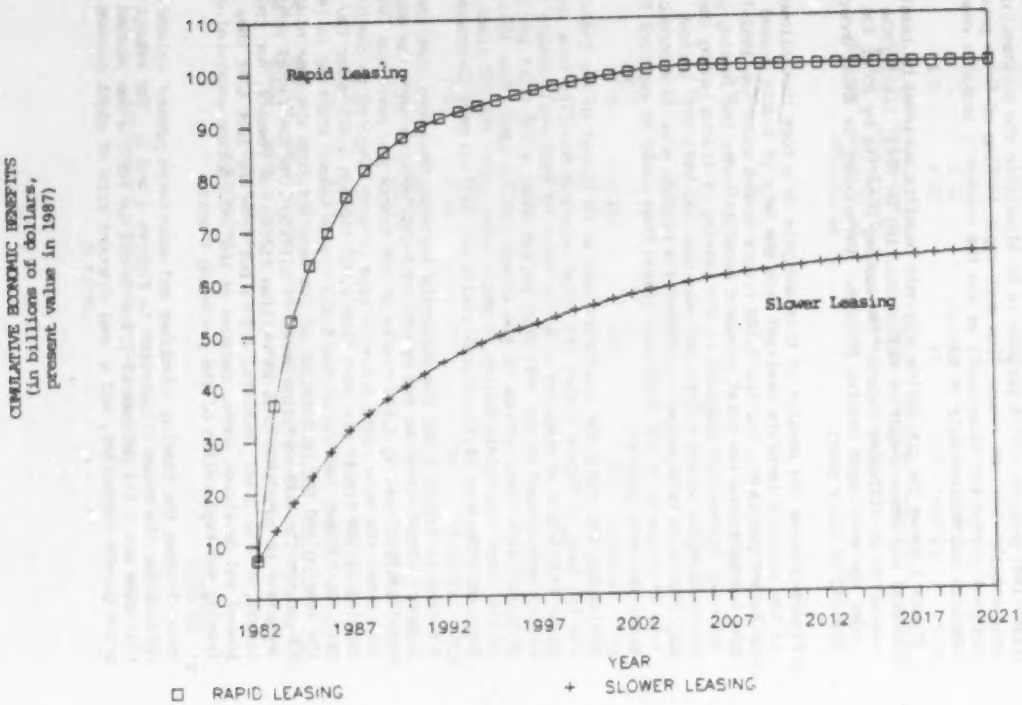


Figure 2
ECONOMIC BENEFITS OF
RAPID AND SLOWER LEASING PROGRAMS
CENTRAL AND WESTERN GULF OF MEXICO

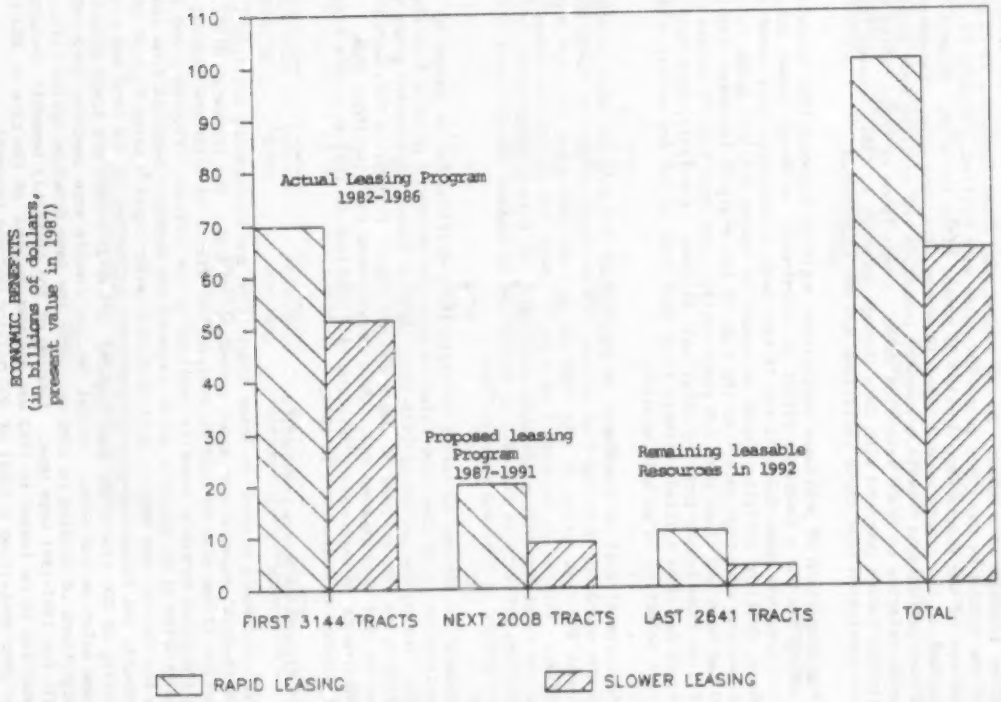


TABLE 7

ECONOMIC BENEFITS OF RAPID AND SLOWER LEASING PROGRAMS

CENTRAL AND WESTERN GULF OF MEXICO

YEAR	NUMBER OF TRACTS LEASED: RAPID LEASING	NUMBER OF TRACTS LEASED: SLOWER LEASING	PRESENT VALUE OF ECONOMIC BENEFITS IN YEAR LEASED: RAPID LEASING ($ Millions)	PRESENT VALUE OF ECONOMIC BENEFITS IN YEAR LEASED: SLOWER LEASING ($ Millions)	PRESENT VALUE OF ECONOMIC BENEFITS IN 1987: RAPID LEASING ($ Millions)	PRESENT VALUE OF ECONOMIC BENEFITS IN 1987: SLOWER LEASING ($ Millions)
1982	182	182	4,974	4,974	7,388	7,388
1983	1,029	280	21,782	4,234	29,634	5,760
1984	814	200	12,679	4,234	15,972	5,333
1985	619	200	9,160	4,234	10,684	4,938
1986	500	200	5,751	4,234	6,211	4,572
SUBTOTAL: Tracts Leased in 1982-1986	3,144	982	54,346	21,908	69,810	27,911
1987	555	200	6,682	4,234	6,682	4,234
1988	476	200	5,452	3,277	5,048	3,035
1989	363	200	3,977	3,115	3,409	2,671
1990	330	200	3,499	3,115	2,778	2,473
1991	284	200	2,921	3,115	2,147	2,290
SUBTOTAL: Tracts Leased in 1987-1991	2,008	1,000	22,531	16,857	20,065	14,702
1992	200	200	2,005	2,993	1,364	2,037
1993	200	200	1,976	2,960	1,245	1,865
1994	200	200	1,945	2,960	1,135	1,727
1995	200	200	1,913	2,505	1,033	1,353
1996	200	200	1,879	2,300	940	1,151
1997	200	162	1,843	1,863	853	863
SUBTOTAL: First 3144 Tracts Leased in Slower Program		3,144		54,346		51,610

TABLE 7 (cont.)

YEAR	NUMBER OF TRACTS LEASED: RAPID LEASING	NUMBER OF TRACTS LEASED: SLOWER LEASING	PRESENT VALUE OF ECONOMIC BENEFITS IN YEAR LEASED: RAPID LEASING ($ Millions)	PRESENT VALUE OF ECONOMIC BENEFITS IN YEAR LEASED: SLOWER LEASING ($ Millions)	PRESENT VALUE OF ECONOMIC BENEFITS IN 1987: RAPID LEASING ($ Millions)	PRESENT VALUE OF ECONOMIC BENEFITS IN 1987: SLOWER LEASING ($ Millions)
1997		38		540		250
1998	200	200	1,805	2,877	774	1,234
1999	200	200	1,765	2,854	701	1,133
2000	200	200	1,723	2,830	634	1,041
2001	200	200	1,680	2,804	572	955
2002	200	200	1,634	2,776	515	875
2003	200	200	1,587	2,747	463	802
2004	200	200	1,537	2,715	415	734
2005	41	200	305	2,682	76	671
2006		200		2,647		613
2007		170		2,218		476
SUBTOTAL: Next 2008 Tracts Leased In Slower Program		2,008		27,690		8,784
2007		30		382		82
2008		200		2,570		.511
2009		200		2,529		465
2010		200		2,486		423
2011		200		2,441		385
2012		200		2,394		349
2013		200		2,344		317
2014		200		2,292		287
2015		200		2,239		259
2016		200		2,183		234
2017		200		2,124		211
2018		200		2,064		190
2019		200		2,001		170
2020		200		1,935		153
2021		11		103		8
SUBTOTAL: Last 2641 Tracts Leased	2,641	2,641	23,596	30,085	10,722	4,045
TOTALS:	7,793	7,793		1987 PRESENT VALUE:	100,596	64,438
				DIFFERENCE:	36,158	

For the rapid leasing scenario, the tracts leased from 1982-1985 are the actual program results. The one exception is Sale 102 where it is assumed that all of the bids received were accepted. For these years, the net economic values of the resources are determined by dividing the total bonus on leased tracts by the ratio of bonus bids to total government receipts of 0.37. Some comments have suggested that the areawide program reduced competition in the lease auctions, resulting in lower bonuses on each tract than would have been received under a slower leasing program. A recent GAO study,[1] for example, estimated that bonuses would have been $3.1 million more per tract under tract selection. Although there is substantial debate over the correctness of the methods GAO used to calculate this number (see Section V of this appendix), $3.1 million per tract were added to the bonus revenue in 1983-1985 before dividing by 0.37.

For 1986, the number of tracts leased is set at 500, which is reasonable in light of the trend in tracts leased from 1983-1985. The amount of resource leased is determined by subtracting the risked leasable resources in the proposed program (Appendix F, Table 8) from the expected resources in the 1982 program document. It is assumed that, on average, each tract leased in the current program has the same quantity of resources, and the resources leased in 1986 is this average multiplied by the 500 tracts. The net economic value per barrel is also taken from the 1982 program assumptions, but it is adjusted for the price decline that has occurred in the ensuing years.

For subsequent years, the pace of leasing is determined by estimates of remaining leasable resources. In each year, the leased tracts are assumed to contain an average of 2.0 million barrels of oil equivalent each. Table 1 in Appendix R shows the developable resources expected to be leased from 1987-1991. Adjusting these to leasable resources and dividing by the average volume of resources per tract results in the number of tracts leased per year. After 1991, it is assumed that 200 tracts per year are leased until all of the currently leasable resource has been leased. The net economic value is determined from the estimated net economic value per barrel of oil equivalent (boe) (Appendix F, Table 6A) with the assumed price growth and a constant cost of $4.00/boe, which reflects the maturity of production technology in the Gulf of Mexico.

It is likely that the best tracts are leased first, and that the tracts being leased decline in value as leasing proceeds. This decline is modeled by constructing a linear decline in value of the tracts over the course of the leasing program. The net economic value per tract is assumed to decline linearly from 1.5 times the average tract value to just over half of the average value when leasing stops.

In the slower leasing scenario, 200 tracts per year are leased throughout the program. An underlying assumption of the comparison of different leasing rates is that the same tracts are leased in the same order under each scenario. Thus, the net economic value per tract of the first 1,000 tracts leased in 1983 under the rapid leasing program must be applied to the years 1983-1987 in the slower program. This method of assigning net economic value

[1] GAO, Early Assessment of Interior's Area-Wide Program For Leasing Offshore Lands, July 15, 1985.

to the 200 tract per year schedule is applied until all of the resource leased under the current program has been leased in the slower approach. Holding the net economic value per tract under the slower leasing program equal to the net economic value per tract leased under the more rapid program may not yield good estimates of the actual values realized from slower leasing. On the one hand, the values are underestimated because the gains from the assumed price growth after 1987 are not included. On the other hand, the estimated values under the slower program tend to be overstated because they do not reflect the declines in price and price expectations that occurred between the intial areawide leasing and the time the same tracts would be leased under a 200 tract per year program. Starting in 1997, the linear decline formula is used to estimate the net economic value.

As discussed earlier, more rapid leasing typical of the areawide approach provides an extra $36 billion of economic benefits over slower leasing typical of tract selection, in 1987 present value. About $18 billion of this difference is realized by earlier leasing and development of the tracts leased during the current program. The remaining difference arises from two sources: the earlier realization of the benefits from tracts leased under the more rapid program in the years 1987-1991 and the leasing of those tracts with leasable resources remaining to be leased in 1992 that occurs earlier because of accelerated leasing in the preceding years.

Six other cases were analyzed to see how this difference would vary under alternate assumptions. These results are presented in Table 8. The first variation assumes that the bonus bids under the rapid leasing scenario accurately reflect the economic rents associated with the leased tracts. The actual bid data are used to determine the net economic value of the tracts leased in 1983-1985, without the additional $3.1 million per tract assumed in the initial case. This should reduce the value of the first 3,144 tracts leased and, therefore, the benefits of more rapid leasing. In this case, the difference in present value between the two leasing scenarios is over $28 billion.

The next set of variations alter the basic economic assumptions, using a two percent price growth, a six percent real discount rate, and a combination of the two. In these cases, the net economic value per barrel was varied in accordance with Table 13 in Appendix F. Both the higher rate of price increase and a lower rate of discount increase the value of leasing in later years and reduce the difference between the economic benefits of the two leasing rates. With these assumptions, an extra $26 billion to $34 billion of economic value are gained under more rapid leasing.

An additional advantage of rapid leasing is the flexibility that it allows in the actual rate of leasing. This is illustrated by including a ten dollar price shock in the year 2000 in the leasing scenarios. Prices are assumed to rise suddenly to over $37. It is assumed for purposes of analysis that such a price shock would result in doubling the rate of leasing to 400 tracts in the years 2000 and 2001 under areawide leasing, an increase in the average net economic value of 59 percent in all years following the shock, and an increase of seven percent in the total leasable resource resulting from additional tracts becoming economic at the higher prices. One would expect that the ability of more rapid leasing to bring the newly appreciated tracts into development at an earlier time than leasing at 200 tracts per year should

result in an increased difference between the total present values of the two programs. In this model, however, the gains from more rapid leasing are $32 billion, roughly $4 billion below the initial case. This results from the fact that, under the rapid leasing scenario, all of the remaining leasable resource will have been leased within three years after the price shock, while leasing continues until 2077 under the slower leasing program. Thus, the benefits from the greater net economic value per barrel after the shock apply to a larger proportion of the total currently leasable resource under the slower leasing program. In effect, the slower leasing program captures the additional benefits as a return on correctly speculating on the sudden increase in value in later years.

Finally, the initial case assumes that the development profile of a tract is the same under both leasing options. Some commentors have suggested that industry will be unable to explore and develop tracts leased under the areawide program in the same number of years as it had under earlier programs because developing the larger number of leased tracts would strain its resources. The final case inserts an additional three-year lag between leasing and development in the rapid leasing scenario in those years where the program results in a greater number of tracts being leased than are leased in the slower program. The gains from more rapid leasing are over $15 billion in this scenario.

More rapid leasing typical of the areawide or focused-on-promising-acreage approaches in the Central and Western Gulf of Mexico provides substantial gains to the economy that would not be realized under the slower leasing typical of the tract selection approaches. The benefits from the more rapid pace of leasing range from $15-35 billion. The substantial nature of these gains holds up under a variety of economic assumptions. The gains are divided between three periods: $15-20 million from the accelerated leasing of the current program, about $10 billion from the earlier and more rapid leasing in the proposed program, and another $6 billion from the earlier leasing and development of all remaining resources after the proposed program expires.

E. Future Effects of the Pace of Leasing

An issue that arises in formulation of the third 5-Year OCS Leasing Program is the effect of offering tracts at different rates during the 1987-1991 period upon the rate and sequence of future investments in exploration and development and upon the resulting economic benefits. Both price expectations and the inventory of unleased tracts will be different in 1987 than they were in 1982. If expectations about future oil and gas prices are much lower in 1987-1991 and leasing must draw from an inventory that has been substantially depleted of promising new prospects, there would be less difference in the rate of investment under a slower pace of acreage offerings as compared to more rapid offerings. The total acreage leased could tend to be similar, since the amount of prospective unleased acreage at the time of each sale would be moderate. Under either restricted offerings or large offerings, however, both the Federal Government and investors must evaluate the whole area to find promising prospects. For restricted offerings to achieve investment results similar to larger offerings, the Government must also be able to identify all prospects ready for investment. Larger offerings allow flexibility for bidding to adjust to information produced in the months between the sale and the time at which the Government would select the limited

TABLE 8

COMPARISON OF ECONOMIC BENEFITS UNDER DIFFERENT LEASING AND ECONOMIC ASSUMPTIONS

CENTRAL AND WESTERN GULF OF MEXICO

PRESENT VALUE OF ECONOMIC BENEFITS IN 1982
($ Millions)

DESCRIPTION OF CASE	FIRST 3144 TRACTS		NEXT 2008 TRACTS		REMAINING 2641 TRACTS		TOTAL		DIFFERENCE
	RAPID LEASING	SLOWER LEASING	RAPID LEASING	SLOWER LEASING	RAPID LEASING	SLOWER LEASING	RAPID LEASING	SLOWER LEASING	
BASE CASE	69,810	51,610	20,065	8,784	10,722	4,045	100,596	64,438	36,158
UNADJUSTED BIDS	43,440	32,774	20,065	8,784	10,722	4,045	74,227	45,603	28,624
22/YEAR PRICE GROWTH	69,810	51,610	20,552	10,992	12,466	5,766	102,828	60,297	34,531
6% DISCOUNT RATE	65,645	51,734	20,617	11,556	12,889	6,536	99,150	69,826	29,324
22 PRICE GROWTH & 6% DISCOUNT RATE	65,645	51,734	21,130	14,399	15,039	9,344	101,814	75,477	26,336
PRICE SHOCK	69,610	51,610	20,065	12,422	13,714	6,748	103,589	70,799	32,790
3-YEAR INCREASE IN DEVELOPMENT LAG UNDER RAPID LEASING	56,924	51,610	15,928	12,541	10,722	4,045	83,574	68,196	15,378

NOTES: Base case assumes an 8% real discount rate, 12/year price growth, $24/bbl in 1/87, and a value decline that is a linear decline of the NEV per tract from 1.5 * (average tract value) to .51 * (average tract value)for rapid leasing and .50 * (average tract value) for slower leasing.
Unadjusted bids case determines the NEV using the actual bids for the years 1983-1985 (see text).
Price shock occurs in 2000 and causes an increase in rapid leasing from 200 to 400 tracts in 2000 and 2001, a permanent 5% increase in average tract value, and an increase of 325 total tracts leased.

acreage to be offered. Wider offerings also provide more flexibility to increase rapidly the amount of acreage leased if oil prices increase rapidly again. This could be particularly true if the administrative processes for restricted sales were to be accompanied by reduced administrative capacity (budget and manpower), placing constraints on increases in the acreage to be offered.

The differences in investments and resulting economic benefits under restricted and wider offerings would tend to increase whenever changing conditions caused a substantial inventory of prospects worthy of investment to accumulate amidst unleased acreage. Larger offerings would allow investments in lease acquisition, exploration and development to adjust quickly to changing conditions, removing good prospects from the unleased inventory relatively sooner after their emergence than would restricted offerings.

The tract selection procedures of the 1970s made it difficult to increase the acreage offered when conditions warranted. The leasing experience of the 1970s shows that the longer the restriction in the availability of prospective acreage, the greater is the buildup of demand for investment and the greater the potential jump in the rate of investment when acreage is finally made available. The rapid increases in seismic evaluation, acreage leased and exploratory drilling in 1983 and 1984 could have been smoothed out over 5 or 6 years had more acreage been made available starting in 1976. It is ironic that the heavy investments in 1983 and 1984 came just as world oil prices were declining, putting much of this investment "out of phase" with potential returns. Had more acreage been made available in 1980 and 1981, the expected net economic value, the government revenue, and the expected private returns could all have been higher. Had it been available starting in 1976, before the peak in oil prices, many of the actual investments would have been more timely and would have yielded greater economic benefits, though government revenues in (nominal dollars, undiscounted) could have been somewhat less than they would have been in 1980.

In summary, effects on investments and economic benefits caused by differences in the pace of lease offerings will tend to be greater the more rapid and extensive are the changes in oil price expectations and geological knowledge in the future. Restricted offerings tend to perform adequately in a relatively stable world while wider offerings allow more flexibility for investments to adapt to changing conditions.

IV. A Framework for Assessing Revenue and Fair Market Value Consequences

A substantial part of the controversy over more rapid OCS leasing has been the charge that it reduces Federal lease revenues and violates the requirement to assure receipt of fair market value. To address this concern, it is appropriate to review the relationship between the pace of leasing, the bidding for leases, the resulting revenues and the fair market value requirement. This section discusses these relationships.

These relationships are complicated by the fact that there are different forms of Federal revenue. The lease revenues include cash bonuses, rentals and royalties. The cash bonuses paid at the time leases are issued are the most well-known form. Rental fees are relatively small annual payments made by the lessee. Royalties are collected years after leases are issued, being a

percentage of the value of the oil and gas produced. In addition to lease revenues, any profits lessees make contribute to the firm's taxable income and presumably its tax payments to the Federal Government. (Income tax revenues, of course are collected by the Internal Revenue Service and are not accounted for on a lease-by-lease basis.)

The cash bonus paid for a specific tract can be affected by geologic and economic conditions that affect the tract's net economic value as well as conditions that affect the portion of its perceived value that firms are willing to bid. Since the pace of lease offerings in general can affect the time at which a tract gets leased and the state of knowledge about the geologic and economic conditions during which it gets leased, the pace can affect the tract's net economic value at the time it is leased. Similarly, the pace of leasing can affect the portions of tract values that firms bid. Thus the pace of leasing can cause the amount of bonus paid for a specific tract to be higher or lower.

The pace of lease offerings also affects the number of tracts leased in a given sale or period and, as discussed in sections II and III, the mix of tracts of different values that is leased. The total bonus revenues in a sale or period can be greater if more tracts are leased, or if higher value tracts are leased. It is possible for total bonus revenues to increase despite the fact that the bonuses for specific tracts are less than they could have been under different circumstances. The reverse is also true, namely that total bonus revenues can decrease while bonuses for specific tracts are more than they would have been.

Royalty and tax revenues can be affected by the pace of leasing because the pace, in part, determines the timing of the investments needed for production to occur. In general, these downstream revenues will occur earlier when leases are issued earlier. If resource and price expectations are borne out by exploration and future events, the leasing of more acreage in the present means higher royalty and tax revenues from OCS leases in the period 5 to 25 years from the present.

In fact, differences in the pace of leasing mean differences in the timing of revenues of all forms. To assess the revenue effects of different leasing rates, it is necessary to account for the fact that having tracts leased in one period means they will not be leased (at least until relinquished) in any later period. Increased leasing in the present tends to shift the revenues to be derived from the Government's land forward in time at the expense of revenues in later periods.

Discounting to present value is the appropriate method for measuring the effects of such revenue shifts just as it is for assessing the effects of timing on economic benefits as discussed in Sections II and III. Discounting allows for the benefits of receiving revenues earlier to be weighed against decreases in the undiscounted amounts that may also result. For example, a $2 million bonus today is equivalent in present value terms (at an 8 percent discount rate) to a bonus of $2.7 million 4 years from today, and to a $3.7 million bonus 8 years from today. A $5 million bonus today is equivalent to a bonus of $6.8 million in 4 years and a $9.3 million bonus in 8 years. A bonus 9 years from today would have to be twice as much as a bonus today to be equal in present value terms.

Thus, in formulating a leasing program it is useful to analyze the extent to which various factors affect bonus bids and other forms of revenue. In particular, it is important to separate the revenue effects of perceived tract characteristics and economic conditions at the time at which leases are sold from the effects of the pace of leasing on the competitive bidding process. Furthermore, it is necessary to account for the effects of receiving revenues at different times under different leasing rates. Correctly analyzing these various effects is a complicated task.

The effects of the pace of leasing on the competitive bidding process may also affect assurance of fair market value. Appendix K sets forth the legal and economic meaning of the fair market value requirement and describes the policies and procedures now in effect for meeting that requirement. The primary concept is that the fair market value of a property is determined by reference to the price it would bring in a competitive market through transactions between knowledgeable and willing buyers and sellers. In the absence of market prices, or if the competitive bidding process is so flawed that market prices cannot indicate fair market value, other means of determining or assuring fair market value are used. The MMS bid adequacy procedures are based on this concept.

Since the market price for an OCS lease is the highest competitively bid cash bonus the government receives, Federal bonus revenues are related to fair market value. However, the case law on fair market value makes clear that fair market value is a legal standard that establishes a minimum regarding what is acceptable for a lease but does not require maximization of revenues. (See, for example, California v. Watt, 712 F. 2d 584, U.S. Court of Appeals, District of Columbia Circuit, July 5, 1983.) Furthermore, because it is tied to market prices, the fair market value of a particular property can increase or decrease as conditions which affect market prices vary. Thus, substantial variation in Federal leasing revenues can occur as prices in the lease market change, without violation of the fair market value requirement.

In assessing the revenue and fair market value effects of the pace of leasing, it is important to distinguish between the factors that affect the market price of leases and the resulting Federal revenues without preventing assurance of fair market value, on the one hand, and factors that affect assurance of fair market value, on the other. Legally and technically speaking, concerns about meeting the fair market value requirement are limited to the adequacy of competition in cases for which competition is relied upon and the adequacy of the Government's tract evaluation and bid rejection policies in cases for which they are relied upon. In some cases, of course, both competition and tract evaluation are used.

The adequacies of competition and Government procedures can be analyzed and debated at length. Even if such analysis shows that leasing would be in technical compliance with the fair market value requirement, there is likely to be the perception that any failures on the Government's part to get as much as conceivable for leases are violations of the fair market value requirement. Thus, various means for increasing Federal leasing revenues can be considered, not only for their deficit reduction benefits but also for the increase they may yield in public confidence in the conduct of the leasing program.

If market prices competitively determined are the preferred measure of fair market value, then the issue arises, can the price at which properties are sold always be regarded as fair market value? More particularly, is any high bid received for an OCS lease to be regarded as fair market value? It has been argued that since the sealed bidding process is competitive, each bid submitted must reflect the possibility of competitive bids even if none materialize. This argument is supported by the concept of an equilibrium in the distribution of bids over the many tracts bid upon simultaneously. If a firm could identify a class of tracts for which the high bids would be substantially less than fair market value, it could reap more profit by shifting its bids into that class. The distribution of bids that results from many firms' efforts to find such situations tends toward an equilibrium in which the returns expected from all lease acquisitions tend to be similar.

A situation identified by the Commission on Fair Market Value Policy for Federal Coal Leasing which argues against automatically using market prices as a standard for "fair market value" is monopolistic manipulation of the market. Any seller is a monopolist if it can exert control over a sufficient portion of the supply of a given commodity or property to influence the market price by changing the amount it offers for sale. A monopolist can cause prices to increase by withholding his supply or to decrease by offering more. Monopolists can restrict their output to extract higher profits from their customers. Dominant firms in a market, including monopolists, can "dump" their product at low prices to force competitors out of business. The issue thus arises as to whether market prices in a monopolistic market are adequate measures of fair market value. This issue needs to be addressed in OCS leasing because the Federal Government's dominant role in the supply of offshore oil leases raises the possibility that it could exert power over lease prices in a way similar to that of a monopolist. Arguments have been made that areawide leasing in effect drove down bids by "dumping" too much acreage on the lease market on the one hand and that tract selection leasing could increase prices by exercising monopoly power on the other.

The Coal Commission reviewed the case law on fair market value. It found that the courts have recognized that "the market price may not necessarily be determinative" of fair market value if there is "evidence that the market had been artificially depressed."[1] Since the Secretary, in leasing Federal coal, determines fair market value primarily by an appraisal based on prices in comparable sales, the Commission found that he "should take an active deliberative role in determining whether the sales in question were made under market conditions conducive to arriving at a fair price."[2] Of particular concern was whether "unrestrained leasing might have the effect of depressing an already 'soft' market, with the result that prices obtained in such a market may be below fair market value."[3] Appraisals based on prices in comparable sales that were below fair market value should, therefore, not be used to determine the fair market value of Federal coal leases. Similar concerns have been raised that areawide OCS leasing reduces competition and depresses OCS lease prices below fair market value.

1 Report of the Commission on Fair Market Value for Federal Coal Leasing, p. 619.
2 Ibid., p. 620.
3 Ibid., p. 622.

The operation of a monopolistic lease market can be understood by comparison to the operation of an idealized competitive lease market. Fair market value is defined as the market price determined in a competitive market because such a market allows buyers and sellers to agree to transactions without compulsion and with knowledge from the market. An idealized competitive lease market would involve many sellers and many buyers, though not necessarily in every transaction. Such a market would have developed had the Government sold all, or at least most of, the OCS lands outright many years ago. If no single owner of OCS lands could affect lease prices in general by his decision to lease his oil and gas rights, then lease prices would be competitively determined and would be a good measure of fair market value.

In an idealized competitive lease market, an OCS landowner could decide to withhold his leases to gain from the appreciation in value resulting from expected increases in oil and gas prices or decreases in costs. He would do so using the same rule of thumb as the idealized OCS manager described in Appendix F except that he would compare the rate of appreciation of the proceeds from sale of the tract with his own discount rate rather than the social discount rate. If an individual OCS landowner withheld his oil and gas rights, *whether to his own benefit or detriment, it would not affect the* prices of other oil and gas leases transferred in the market. Similarly, if an individual OCS landowner chose to lease all his land, it would not affect the prices of other leases. The competitive operation of the market would assure that prices were fair market value.

In comparison, an OCS owner with holdings sufficiently extensive to affect lease prices in general could cause lease prices to be higher or lower than the fair market values that would result from the idealized market. If he managed to imitate the supply of leases that would have resulted in an idealized competitive market, then lease prices would be the same as the competitive market lease prices and would be fair market value. To do so, however, would require that he exercise little restraint on the availability of his tracts for lease.

Despite the Government's position as the dominant seller of offshore leases, there are several fundamental limitations to its ability to exercise monopoly power. First is the fact that OCS leases are not bought for their inherent value to the buyer, but for the oil and gas which they may yield. The value of an OCS lease is derived from the expected value of the oil and gas which will be produced if found. The price of oil, in particular, is set by an international market which the United States alone has little ability to affect. The expected price of oil and gas is affected very little by the rate of OCS leasing. As a result, the Government cannot extract true monopoly profits by withholding leases and forcing both lease prices and oil prices to higher levels. The Government can, however, increase the price paid for each lease issued by delaying its sale during periods of rising price expectations. (Appendix F discusses the question of whether this practice is beneficial to the economy.) It might increase its bonus revenues from specific tracts leased in this manner but it is not necessary to do so in order to assure receipt of fair market value, just as it is not necessary to hold a stock while its value is appreciating in order to receive fair market value when it is sold.

The Government is also limited in its ability to cut lease prices. Firms "dumping" their products to inflict financial damage on their competitors (through so called predatory pricing) set prices below their competitors' costs. The Government, however, cannot set lease prices because it must use the sealed competitive bidding process. This means that, even if the Government wished to sell at an amount less than fair market value, any firm willing to pay just slightly more than the going price could enter a bid and win a lease. The profits firms could make by bidding enough to win such tracts but still less than fair market value would tend to attract more firms. Thus, any observable tendency for the market to underprice OCS leases would attract more bids and yield higher prices over time.

It is also worth noting that the OCS tract evaluation method does not raise the issue identified by the Coal Commission regarding fair market value determinations using below fair market value prices from comparable sales. The MMS tract value estimates are made by the discounted cash flow method which uses estimates of tract characteristics, future costs and future oil and gas prices to calculate the net value of the tracts after royalties and taxes. Bonuses bid for other oil and gas leases are not used in this method.

The issue of whether the pace of leasing affects receipt of fair market value thus boils down to two questions. The first relates to tracts for which there is evidence of competition in the submission of three or more bids. The question is whether either lease values or the competitive process is so affected by the rate of leasing that the high bid on such tracts can fail to be at least as great as the market price that would result from a transaction between knowledgeable and willing buyers and sellers. The second is whether the government's tract evaluations and bid rejections can assure receipt of fair market value on tracts for which there is less evidence of competition. These questions will be addressed below.

V. Revenue and Fair Market Value Consequences of the Pace of Leasing

This section describes a number of analyses that have been performed on the effects of areawide leasing. First it examines the revenue tradeoffs inherent in the choice of faster versus slower leasing. In many transactions, the seller must choose between a certain and immediate sale at a lower price on the one hand and an uncertain later sale at a higher price on the other. Since the Government retains a rental and royalty interest in tracts leased and stands to collect taxes on profits as well, this type of tradeoff involves consideration of the differences in timing of these revenues as well as of the bonus or cash price paid at the time of the lease sale. The analysis described below shows the gains that result from receiving all forms of revenue sooner because of the larger lease sales in 1983, 1984 and 1985 as compared to continued tract selection sales. Bonus decreases equal to such gains could be incurred without a net loss to the Treasury. In other words, this analysis shows the maximum decrease in bonuses that could have resulted from the areawide and focused-on-promising-acreage lease sales held in 1983 through 1985 while not costing the public financially.

Second, it describes a variety of analytical methods used to assess the extent of change in the bonuses paid for tracts leased that results from various causes. The approach is to analyze each cause-and-effect relationship itself

to determine how sensitive tract values and bonuses are to each cause of change. This approach has been used to assess the likely bonus effects of the pre-sale nominations, oil prices, water depth, number of bidders, and the likely effects of larger lease sales on the number of bids received.

Third, this section describes the results of using statistical regression techniques to analyze data on changes in observable variables which are believed to be related. This approach uses mathematical techniques to determine the extent to which variations in one variable are associated with variations in another variable. By statistically controlling for the effects of other factors affecting bonuses, regression may be able to provide estimates of the change in bonuses associated with larger lease sales. This method has been used by both the General Accounting Office to analyze the relationship between the bonuses paid for leases in both tract selection and areawide sales, and such factors as the size of the sale, oil and gas prices, resource potential, water depth, and the number of bids.

A. Tradeoffs in the Timing of Revenues

The large lease sales in the Gulf of Mexico during 1983, 1984 and 1985 resulted in much more acreage being leased than the historic rate. During 1983, 1984, and 1985, 2,447 leases were issued for $8.5 billion in the Central and Western planning areas. If the previous tract selection procedures had been used to offer these blocks, some of the blocks would not have been leased until 1994 or later. The Federal Treasury benefited from receiving those bonuses in 1983, 1984, and 1985 rather than receiving them over a longer period because revenue today is always more valuable than the same amount of revenue received in a later time period.

The precise benefit of receiving bonuses earlier can never be known, however. The bonuses which might have been paid for the blocks if they were leased in a different year than they were actually leased would most likely be different than the actual bonuses received. Geologic information would be different, either increasing or decreasing the value of some blocks. Economic expectations would likely be different from what they were in 1983, 1984, and 1985 which would lead to a different bonus being offered than was offered when the block was leased. It is possible, however, to estimate how much more, on average, each block would have to receive if leasing proceeded at a slower pace in order to equal the value of the revenues received in 1983, 1984 and 1985.

From Table 1 it can be seen that the average rate of leasing in 1978 through 1982 in the Central and Western Gulf of Mexico planning areas under tract selection procedures was about 1.0 million acres a year. This translates into about 200 leases a year being issued. The leasing in 1983, 1984, and 1985 represents 12 years of leasing at 200 blocks per year. Bonuses in tract selection sales would need to be an average of $1.3 million more per block or $3.2 billion more in total for the bonuses to yield the same value to the Federal treasury as did the bonus revenue actually received in 1983, 1984, and 1985.

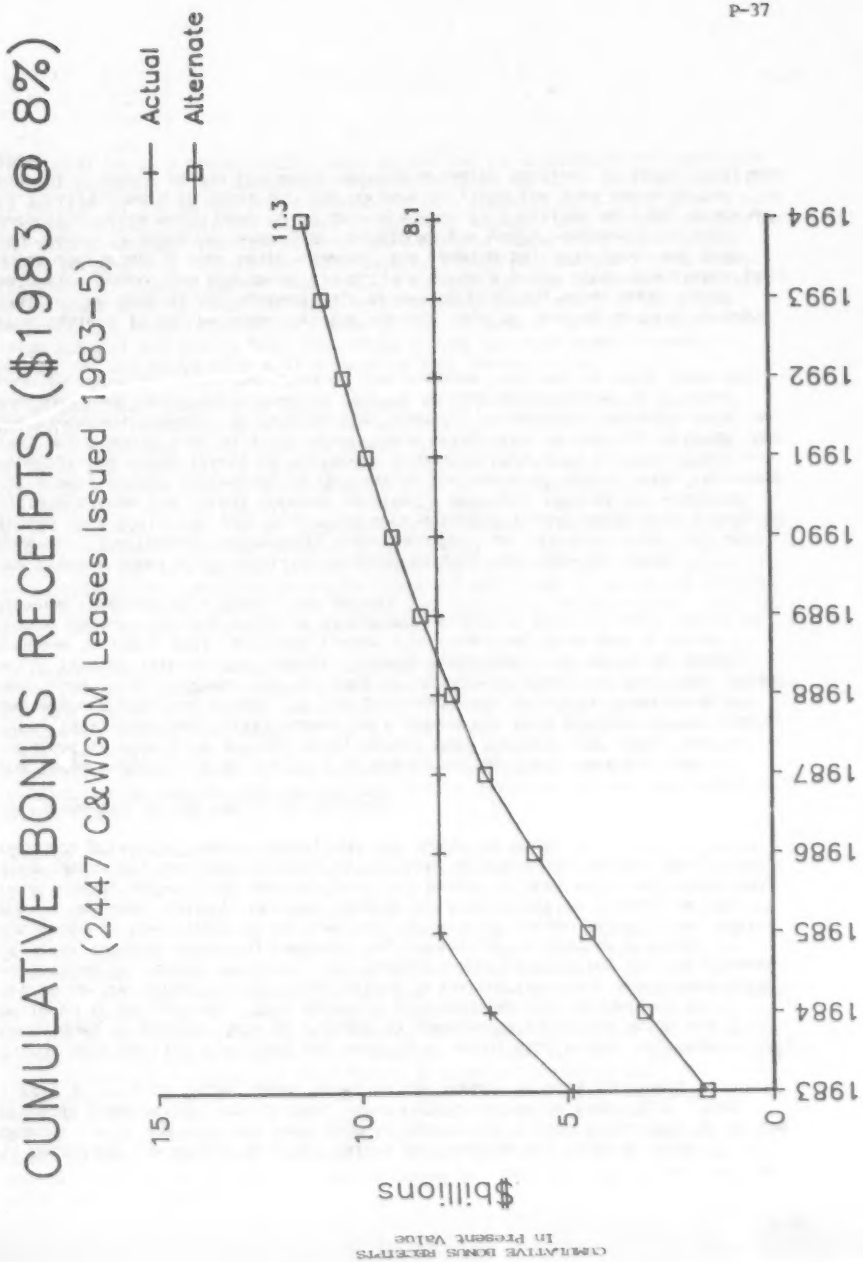
Even if bonuses had been $3.1 million more per block, as the GAO[1] estimated for tract selection sales, it would not be until 1989 (using an 8.0 percent discount rate) that the Federal Government would have received the same present value of bonus revenues. Figure 3 shows this effect. This graph shows the cumulative bonus receipts from the areawide sales held in 1983, 1984, and 1985 in the Central and Western Gulf of Mexico planning areas. The present value in 1983 of the bonuses received is $8.1 billion. Figure 3 also presents the cumulative present value resulting from leasing at approximately 200 tracts per year under the assumption that each tract received, on average, $3.1 million more than it actually did in the large sales held in 1983, 1984 and 1985. By 1994, the 1983 present value would have been $11.3 billion, but the present value of the bonuses from a slower rate of leasing would not have equalled the actual value of the bonuses received until 1989. While the slower rate of leasing would eventually yield a greater total in present value if each tract drew $3.1 million more in bonus, other forms of revenue should also be considered.

The Federal Government also receives royalties, corporate income taxes, and windfall profit taxes[2] from those leases that are productive. These revenues will also be received earlier by the Federal Government from earlier leasing of the tracts. The nominal value of these revenues may be increased or decreased depending on differences in prices and tax laws, but an estimate of the present value benefits from receiving them earlier can be made given certain assumptions.

The highest bonus any firm should be willing to spend for a lease is that residual value after royalties, taxes, and exploration and development costs which produces precisely an expected after-tax rate of return which is equal to the rate of return on the best alternative investment. Discounted cash flow models can estimate the residual values, royalties and taxes for specified tract characteristics. At an 8 percent discount rate, the residual value of tracts typical of those being leased in the Gulf of Mexico has been estimated to be between 25-50 percent of total Government receipts, i.e., other Government receipts are estimated to be 1-3 times the expected residual value which can be paid as a bonus to lease the tract. Assuming other Government receipts will turn out to be 1.5 times the bonuses actually received, the total present value gain from leasing the 2,447 tracts in 1983, 1984, and 1985 instead of the 1983-1994 period is $5.3 billion in 1983.

Thus, because the Federal Government benefits from receiving revenues earlier rather than later, bonuses can be significantly less with earlier leasing and still have the present value of revenues remain the same as it would be with much higher bonuses received later. An analysis was done using discount rates of 6.0 and 8.0 percent and the assumption that other Government receipts are 1.5 times the higher bonuses received in later time periods under the 200 tract per year leasing rate. The bonuses from slower leasing would have to average at least $7.5 million more per tract than they did when leased in 1983, 1984, and 1985 for the two revenue streams to have the same present value. In other words, bonuses in the larger sales of 1983, 1984, and 1985

[1] GAO, Early Assessment of Interior's Area-Wide Program For Leasing Offshore Lands, July 15, 1985.
[2] The windfall profit tax is scheduled to be phased out between 1987 and 1990.



could be more than $7.5 million per tract lower than they would have been in tract selection sales over the 1983-1994 period without causing an overall loss to the Treasury. This is a "breakeven" amount of bonus reduction.

Lower bonuses, however, result in smaller write-offs against future Federal taxes. When one considers that lower bonuses would also result in higher taxes, these assumptions result in bonuses which would have to average in excess of $10 million more per tract in tract selection sales for equal present values.

Estimation Method

A number of specific assumptions were made in estimating the $7.5 million "breakeven" bonus reduction. It was assumed that the 1029 tracts leased in the Central and Western Gulf of Mexico areawide sales in 1983 would have been leased in tract selection sales over a five-year period at a uniform rate. Similarly, the 814 tracts leased in 1984 areawide sales would have been leased in tract selection sales from year five to year eight (assuming 1983 was year 0) at a uniform rate and similarly, the 604 tracts leased in the 1985 areawide sales would have been leased in tract selection sales from year 9 to year 11 at a uniform rate.

To simplify the analysis, it was also assumed that oil and gas prices and expectations were not changing over the leasing and production periods. While this may not be the actual situation over the next 20 or 30 years, this assumption has the advantage of focusing the analysis on the timing of receipts to the Treasury rather than on the timing of leasing vis a vis world oil price trends. (In fact, areawide leasing may well have leased many tracts relatively early in a period of declining oil prices and oil price expectations whereas tract selection leasing would have resulted in leasing many of these tracts later in the period of price decline.)

It was also assumed, for purposes of the initial analysis, that the lengths of time from lease issuance to exploration, development and production milestones were unaffected by the shift from tract selection to areawide leasing. If these time periods were increased by the buildup of firms' inventories of tracts, it could change both bonuses and other revenues. While both would be reduced, their relationship might change as well.

An equation was developed that would give an estimate of the amount by which average bonuses would need to be increased by leasing more slowly in tract selection sales for the total revenues from the leases issued in these sales to have the same present value to the Treasury as the total revenues from issuing the leases in the areawide sales of 1983, 1984, and 1985. The variables in this equation are:

PI = the ratio of other Government revenues (rental, royalty, and tax payments) to the bonuses at the break even level, i.e. PI multiplied by the bonus equals the present value of other Government revenues.

Omega = the increase in present value of taxes because of the effect on taxes from a lower bonus tax write off.

Delta = gain in bonus value per tract from earlier leasing during 1983, 1984, and 1985 in the Central and Western Gulf of Mexico planning areas. Average

bonuses in tract selection sales would have to be higher by an amount equal to delta for the present values of the two revenue streams to be equal.

Delta is the solution to the following equation:

$$\text{Bonus}_{83} + PI*(\text{Bonus}_{83} + \text{Delta}*\#\text{tracts}_{83}) + \text{Omega}*(\text{Delta}*\#\text{tracts}_{83}) +$$

$$(1/1.08)*\text{Bonus}_{84} + PI*(1/1.08)*(\text{Bonus}_{84} + \text{Delta}*\#\text{tracts}_{84}) +$$

$$\text{Omega}*(1/1.08)*(\text{Delta}*\#\text{tracts}_{84}) +$$

$$(1/1.08)^2*\text{Bonus}_{85} + PI*(1/1.08)^2*(\text{Bonus}_{85} + \text{Delta}*\#\text{tracts}_{85}) +$$

$$+\text{Omega}*(1/1.08)^2*(\text{Delta}*\#\text{tracts}_{85}) =$$

$$\sum_{i=0}^{4}(1/1.08)^i*((1+PI)*(\text{Bonus}_{83} + \text{Delta}*\#\text{tracts}_{83})/5) +$$

$$\sum_{i=6}^{9}(1/1.08)^i*((1+PI)*(\text{Bonus}_{84} + \text{Delta}*\#\text{tracts}_{84})/4)$$

$$\sum_{i=9}^{11}(1/1.08)^i*((1+PI)*(\text{Bonus}_{85} + \text{Delta}*\#\text{tracts}_{85})/3)$$

The left hand side of the equation is the present value in 1983 of the revenues from leasing in the Central and Western Gulf of Mexico during 1983, 1984, 1985. The first term, Bonus_{83}, is the actual amount of the bonuses received. The second term, $PI*(\text{Bonus}_{83} + \text{Delta}*\#\text{tracts}_{83})$, is the expected value of the other revenues (royalties, corporate income taxes, windfall profit taxes) the Government will receive. The $\text{Delta}*\#\text{tracts}_{83}$ is included since other Government revenues would not decline even if the bonus declines. PI is the relationship of other Government revenues to the full residual value of a tract. The third term, $\text{Omega}*(\text{Delta}*\#\text{tracts}_{83})$ is the increase in corporate income taxes as a result of a lower bonus of the amount Delta. An Omega of .2 results from a 46 percent marginal tax rate, a write off after 5 years for 70 percent of the tracts which will be non-productive, and a write off over a typical production period for the 30 percent of the tracts which might be productive. Assumptions that more than 70 percent of the tracts will be non-productive would lead to an Omega higher than .2. The other terms of the left hand side of the equation are the same variables for the tracts leased in 1984 and 1985 and discounted to 1983. The terms on the right hand side of the equation represent the present value of Government revenues if they were received over a 12-year period. The first term,

$$\sum_{i=0}^{4}(1/1.08)^i*((1+PI)*(\text{Bonus}_{83} + \text{Delta}*\#\text{tracts}_{83}))/5)$$

is the present value of the revenues from the tracts leased in 1983 assuming they were leased uniformally from 1983 through 1987. The next term is the present value of the revenues from the tracts leased in 1984 assuming they were leased uniformally from 1988 through 1991. The last term is the present value of the revenues from the tracts leased in 1985 assuming they were leased uniformally from 1992 through 1994.

Results

Table 9 presents different values of Delta under varying assumptions. Values of Delta of $4.2 to in excess of $15 million per tract are reasonable estimates of how much lower bonuses could be on average under the leasing rates of 1983, 1984, and 1985 and still have the present value of Government revenues be the same as the present value of Government revenues under the leasing rates of tract selection sales. As stated above, a value of .2 for Omega assumes a very high rate for the percent of productive tracts. The bonus is written off very slowly for productive tracts which results in a small present value change in tax revenues. The assumption of 1.5 for PI is also at the low end of estimates of the current relationship between other revenues and the residual value. Changes in the timing of exploration, development and production might reduce PI, however.

Table 9

Estimates of Breakeven Bonus Reductions
Central and Western Gulf of Mexico Leases
Issued in 1983, 1984 and 1985

Ratio of Other Revenues to Bonuses (PI)	Fractional Increase in Tax Revenue from Lower Bonuses (Omega)	Required Increase in Average Bonus (Delta) (in $ million per tract) @ 6% Discount	@8% Discount
0	0	.9	1.3
.5	0	1.7	2.4
1.0	0	2.7	4.1
1.5	0	4.2	7.5
2.0	0	6.7	16.3
.5	.2	2.4	3.6
1.0	.2	4.2	7.5
1.5	.2	7.6	21.3
2.0	.2	16.7	N/A

B. Factors Affecting Lease Prices

Some factors have been identified through which areawide leasing might affect the amounts bid for leases. These include the reduction in information gleaned by bidders from the nomination and tract selection process and the effects of firms' budget limitations. In addition, changes in the characteristics of the tracts being bid upon can affect the amounts bid as can changing oil and gas price expectations.

Some comments on the current 5-year program have argued that the modification of the nomination process reduces the amount of information available to prospective bidders and thereby reduces competition and the amount that a firm will bid for a lease. The empirical evidence that has been cited to support this claim is the decline in the average bonus per acre for leases in the Gulf of Mexico along with a decline in the average number of bids per tract. A decline in average bids could result from many other causes as well, such as changes in price expectations or leasing of more lower value tracts.

The role of tract nominations in bids does not seem to be substantial. Oil exploration is inherently risky. With current technology, the only way to eliminate (or at least significantly reduce) geologic uncertainty is to drill. Historically, over 85 percent of all exploratory wells in the Gulf of

Mexico have been dry. The information whether somebody has nominated a tract does little to change the perceived riskiness associated with the value of a lease. At most it might affect slightly the perceived risk about the geologic conditions, but it can do nothing to change the other risks associated with exploring for oil and gas.

Historically in the Gulf of Mexico, many millions of acres have been nominated for each sale. The names of companies submitting nominations were made public but the tracts nominated by a specific company were never made public. The information released was a map specifying the tracts nominated and whether they had high, moderate, or low numbers of nominations. In the Gulf of Mexico, the map generally only indicated moderate and low levels of nominations as generally only 1-4 nominations were received. In addition, if companies specified general areas instead of specific tracts in their nominations, the information was not used. This practice diluted whatever value a nomination may have to a bidder. The information that a particular tract has been nominated by someone is of minimal, if any, value to potential bidders in reducing the geologic uncertainty of oil and gas exploration efforts given the inherent risk in exploration. A firm is not going to bid on a tract just because someone has nominated the tract or because the MMS has looked at the geology, looked at the nominations, and selected the tract to be offered in a lease sale. Before making a bid, a firm will collect and analyze geologic and geophysical information,[1] make projections about future oil and gas prices and future development costs if oil and gas are discovered, and estimate the present value of expected profits from exploration and development. Such analysis is substantially more detailed than the information that can be gleaned from the fact that a tract was nominated by another firm. A firm may analyze a tract it otherwise might not if it receives several nominations, however. But given the extent of masking that firms may do when they nominate tracts, it is difficult to judge how important this might be.

Tract selection, by limiting the acreage that was offered for lease, might have lead potential bidders to study some of the tracts to be offered more intensively than the tracts not to be offered, thereby gaining information on the tracts offered that they may not have had otherwise, but the mere fact that Interior selected tracts to be offered conveys little, if any, information.

Some comments suggest that the limited budgets available for bidding can also reduce competition when the pace of leasing is high. Limited budgets do not, in themselves, reduce competition, however. Limited budgets only make people or firms allocate their budgets to items which give them the greatest return. In fact, the basic tenets of modern economics are that all budgets are limited and tend to be applied to items anticipated to provide the greatest returns.

1 MMS also makes lessees' geological and geophysical information available to the public after an initial period of confidentiality. 30 C.F.R. 250.3. Making this information available likely does more to reduce risk than having tract nominations.

The substitutions that result from budget and resource limitations are highly desirable, however. Market allocation and economic efficiency are facilitated by these substitution possibilities. Firms have the option of investing in oil exploration, whether onshore or offshore, on public or private lands, or even in other countries. They also have the option of investing in non-exploration activities. If they choose not to invest in offshore leases, it means that they believe the investment opportunities are better elsewhere. Restricting the acreage available for leasing reduces the ability of the U.S. economy to invest in those domestic projects yielding the highest return and may encourage investment abroad.

An important trend in leasing in the Gulf of Mexico is the shift to acreage in deeper water. As Table 10 shows, this trend accelerated with the implementation of areawide leasing which offered much more deep water acreage. This trend shows a potential for substantially increased investment in exploration and development because of the higher costs of drilling in deep water. It also demonstrates the success of areawide leasing in widening the search for oil and gas.

One of the most important determinants of the value of oil and gas leases is the expected future price of oil. Table 11 presents estimates of tract values calculated by a discounted cash flow evaluation model for several different types of tracts using prices of oil and gas and exploration factors which were used in bid adequacy determinations in past sales in the Gulf of Mexico. The tract value estimates depend on the many other assumptions used, but it is clear that expectations about the future price path for oil and gas strongly influence what the bonus bids will be for any given assumptions about the quantity of the resource expected, and the cost of exploration and development, which in the Gulf of Mexico basically depends on water depth and the depth of the productive horizon. High cost prospects are particularly sensitive. A reduction in the rate of price increase from .02 to zero at $33 per barrel reduces the high cost tract values by 58 to 69 percent. Reduction from $33 to $28 per barrel at zero increase reduces high cost tract values by 57 to 86 percent.

As discussed in section III, tract values are affected by the pace of leasing because of the resulting effects on the characteristics of tracts remaining in the unleased inventory. The value of individual tracts can appreciate if they go unleased while oil and gas price expectations increase or favorable geological data emerge. Value of individual tracts can also depreciate if price expectations decline or unfavorable geologic data emerge. If numerous tracts are appreciating during a period, but fewer are being leased, the resulting inventory buildup will yield higher bids on the selected tracts leased. More rapid leasing after a period of inventory appreciation and buildup will tend to reduce the amounts bid as additional tracts are leased in successive sales. This draw-down effect is accentuated to the extent that more moderate-to-low value tracts are leased during the same period.

Table 10

Leasing by Water Depth
Gulf of Mexico OCS Lease Sales
9/80 through 11/85

Number (Percent) of Tracts Leased by Water Depth

Sale	(Date)	Total	Less Than 200 Meters	200-400 Meters	Greater Than 400 Meters
A62	(9/30/80)	116 (100%)	106 (91%)	4 (4%)	6 (5%)
62	(11/28/80)	67 (100%)	64 (96%)	0 (0%)	3 (4%)
A66	(7/21/81)	156 (100%)	147 (94%)	4 (3%)	5 (3%)
66	(10/20/81)	102 (100%)	91 (89%)	9 (9%)	2 (2%)
67	(2/9/82)	115 (100%)	97 (84%)	10 (9%)	8 (7%)
69 I	(11/17/82)	56 (100%)	50 (89%)	4 (7%)	2 (4%)
69 II	(3/8/83)	11 (100%)	11 (100%)	0 (0%)	0 (0%)
72	(5/25/83)	623 (100%)	490 (79%)	72 (12%)	61 (10%)
74	(8/24/83)	406 (100%)	309 (76%)	55 (14%)	42 (10%)
79	(1/5/84)	156 (100%)	109 (70%)	24 (15%)	2 (15%)
81	(4/24/84)	453 (100%)	258 (57%)	30 (7%)	165 (36%)
84	(7/18/84)	361 (100%)	221 (61%)	61 (17%)	79 (22%)
98	(5/22/85)	409 (100%)	275 (67%)	14 (4%)	120 (29%)
102	(8/14/85)	195 (100%)	118 (60%)	19 (10%)	58 (30%)

Table 11

MMS Tract Value Estimates Under Various Price Assumptions

Oil Price Assumptions			Tract Value Estimates ($ millions)				
			High Cost Resource Size			Low Cost Resource Size	
Evaluation Date	Starting 1/ Oil Price	Annual Price 2/ Change	High	Medium	Low	Medium	Low
7-21-81	$33	0.02	$47.5	$27.0	$10.6	$17.8	$5.6
00-20-81	35	0.01	37.9	20.6	6.5	16.2	5.0
0-09-82	35	0.00	24.3	11.4	0.8	12.6	3.6
5-25-83	28	0.00	8.5	1.2	-5.0	5.6	0.8
3-24-83	29	0.0067	18.2	7.6	-1.2	8.6	2.0
1-05-84	30	0.0067	20.7	9.2	-0.2	9.7	2.4
4-24-84	31	0.0067	23.2	10.8	0.8	10.8	2.8
07/18/84	30	0.01	24.8	11.9	1.3	10.8	2.8
05/22/85	28	0.01	19.5	8.5	-0.7	8.6	1.9
08/14/85	26	0.01	14.2	5.1	-2.7	6.4	1.1

Assumptions used:
Geologic Risk = 0.1
Conditional barrels of oil equivalent by resource size (millions) are:
High Cost--high 120, medium 80, and low 50
Low Cost--medium 30, and low 12
Number of tracts per field are assumed to be 4 in high cost and 2 in the low cost area.
High Cost is equivalent to 400 meters water depth.
Low Cost is equivalent to 100 meters water depth.

1/ Starting prices specified to nearest whole dollar

2/ Annual price change parameter for 1985 sales is an approximation of a new two-part distribution of price changes employed in the evaluation model

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The issue that arises in formulation of the third 5-year OCS Leasing Program is the extent to which the pace of leasing under different procedures in that program would influence lease prices and the assurance of fair market value. Restricted lease offerings that would not offer all of the tracts that could be leased in a particular sale would tend to yield higher average lease prices because fewer low valued tracts would be included in the average. They would also tend to yield higher average bids to the extent that appreciation in the value of tracts occurs while they are withheld from leasing because of increasing expectations regarding oil prices or resource potential. While a higher average value is not necessary for technical compliance with the fair market value requirement, it might provide a higher level of public confidence. On the other hand, continuation of more rapid leasing over the long run would tend to yield prices similar to those of an idealized private OCS market that would clearly be regarded as yielding fair market value. This would yield revenues to the Federal Treasury which are higher in present value.

The actual rate of leasing from continued unrestricted offerings would be determined by the same factors that would influence transactions in a private lease market, namely buyers' and sellers' geologic knowledge and expectations about economic conditions and oil prices. Ironically, in OCS leasing, the potential to drive down bids by offering large amounts of acreage, if it exists at all, could only result after a substantial inventory of valuable unleased prospects had been accumulated over a period of restricted leasing. Continued offerings of substantial acreage could assure that the government would never build up an inventory of leasable tracts large enough to have a depressing effect on bids. While the amount of acreage offered by continuing large sales might be substantial, the amount of prospective acreage considered by bidders and bid upon is likely to decrease substantially from 1983-1985 levels as the inventory is drawn down. The longer such leasing occurs while oil price expectations are declining or stable, the smaller will be the acreage actually leased, even from large sales.

C. Assessment of Competition Effects

Prices in a competitive market are good measures of fair market value because the interaction of many sellers and many buyers assures freedom of choice and provides a source of knowledge. Any seller can turn down an offer from one buyer if he thinks he can do better from another. Any buyer can search for the property and price that meet his needs, using knowledge gained from observing transactions as a guide. Competition helps make buyers and sellers willing and knowledgeable.

Competitive sealed bidding for OCS oil and gas leases provides a competitive process among buyers to assure that each Federal lease is sold to the firm that is willing to pay the most. Competition for OCS leases is usually measured by the number of bids submitted for a tract. In general, criticism of the competitive effects of rapid leasing has been based on the belief that firms bid more if they face more competing bidders on a tract. People generally have more confidence that the high bids on OCS tracts are fair market value if there are more bids on each tract. Thus, there is concern that areawide leasing, by spreading the same number of firms with their limited budgets over many more tracts, has thinned competition and allowed firms to reduce their bids below fair market value without increasing the risk of being outbid.

To assess the effect of competition in past and future lease sales of various types, it is useful to examine in more detail the relationship between the number of bids received and the amount of the high bid on a tract. Figure 4 shows strong evidence of a correlation between the number of bids and the amount of the high bid. It is not clear, however, whether and to what extent this occurs because more bids cause firms to bid greater amounts or because more valuable tracts attract both higher bids and more bidders. It is useful to examine both the theory of bidding on properties of uncertain value and some data from leasing experience to assess these relationships.

Theoretical studies of bidding behavior suggest that the desirable competitive effects of an auction are realized when there are three knowledgeable bidders. These studies suggest that when any bidder anticipates more than three bidders, the income maximizing bidding strategy is to offer a lower bid than he would offer if he only anticipated two other bidders. Failure to make this adjustment increases a firm's chances of winning the tract by being the most over-optimistic bidder. At least theoretically, a firm would not increase its bid for a tract if it expected more competing bids. Under this bidding strategy, more bidders for a lease would still result in a higher high bid, but because of a statistical effect rather than because of competition forcing each bidder to bid higher. It occurs because the greater the number of firms estimating the value of a tract, the higher the highest estimate tends to be.[1]

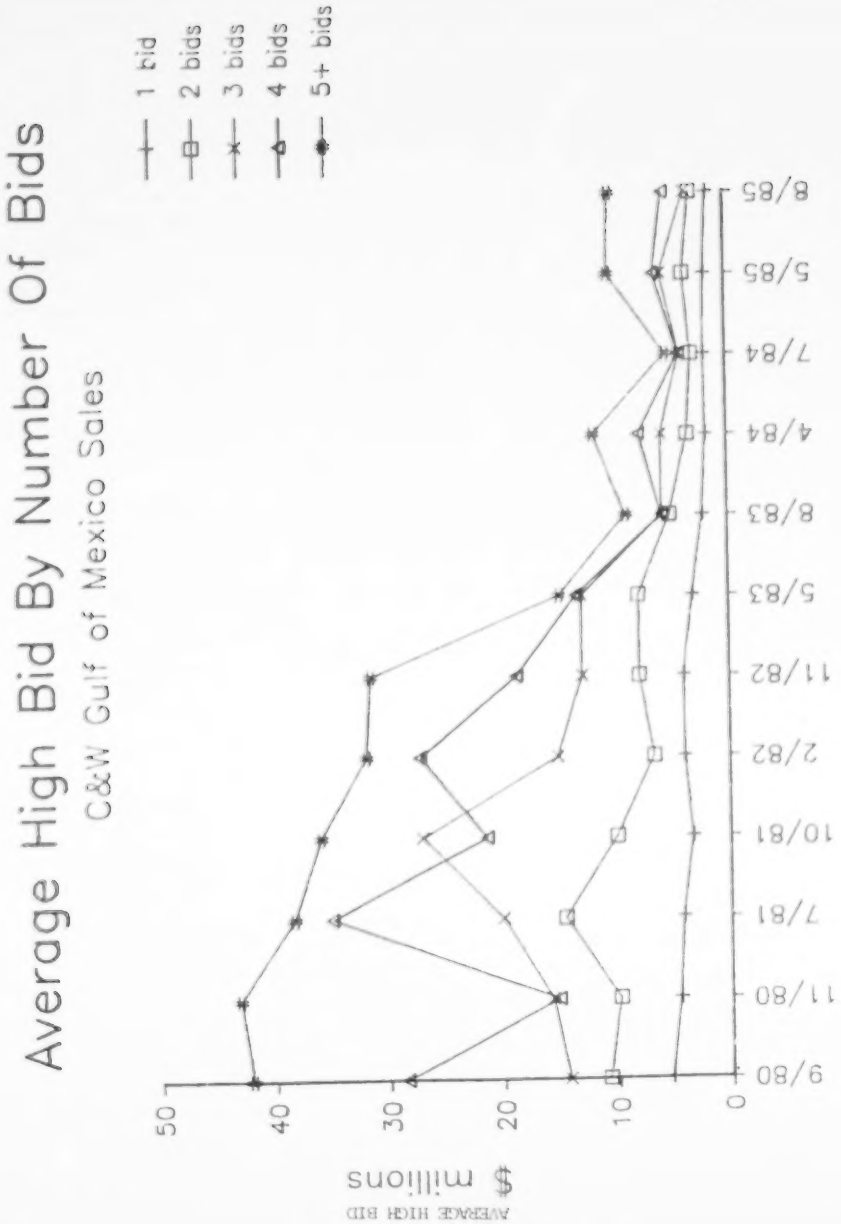
The concept that firms don't bid a higher fraction of their estimate of a tract's value when confronted by more than two other bidders provides a general theoretical underpinning for the three-bid rule used in MMS bid adequacy determinations. When there are three or more bidders for a block, it can be expected that the high bidder has bid the most that competition can bring him to bid. The high bid is therefore reflective of the competitively determined fair market value.

Different levels of competition are to be expected in bidding for items with uncertain value such as oil or gas leases. Two firms evaluating a tract are likely to interpret the geologic information differently and place different values on the tract. For tracts of marginal potential, it is likely that the evaluations by most firms would be less than the minimum submissible bid. For tracts of more promising potential, more evaluations would be above the minimum bid. One would therefore expect more bids on more promising prospects than for more marginal prospects. One would also expect a greater fraction of the tracts to draw only one bid if there were a greater fraction of lower value tracts in the sale.

The evidence from Sales 72, 74 and 79 in the Gulf of Mexico supports the concept that it is the better prospects which receive the greatest number of bids. In January of 1981, the Department issued a Call for Nominations for

[1] For a fuller discussion of the theory of bidding see James Ramsey, Bidding and Oil Leases, JAI Press Inc., 1980; and Albert Smiley, Competitive Bidding Under Uncertainty: The Case of Offshore Oil, Ballinger Publishing Company, 1979.

Figure 4



these sales. Thirty companies submitted nominations on 15.5 million acres. In April of 1981, the Gulf of Mexico offices of the U.S. Geological Survey and the Bureau of Land Management developed recommendations for the selection of tracts to be offered. Their recommendations were developed using the approach employed for previous tract selection sales. In the past, almost all of the tracts selected for a sale were nominated, but not all nominated tracts were offered for lease. The tracts which were thought to have the most promising potential were selected. The concept of areawide leasing was adopted after the BLM and USGS made their recomendations for the tract selections in Sales 72, 74 and 79. Those recommendations were not used to configure lease sales. The recommended tracts were offered as part of areawide lease sales. Bidding on these tracts can be used to test the argument that the relatively more attractive and more obvious prospects attract more bids.

Table 12 shows the average bonus bid and percent of one-bid tracts for selected tracts and others. The average bonus on the tracts receiving bids which both agencies recommended to be included in Sales 72, 74, and 79 was twice the average bonus on the tracts receiving bids which neither agency recommended be included in the sales. This higher average reflects the bidders' perception that these tracts have higher potential. There were substantially more one-bid tracts in the set of tracts neither agency recommended be included. Since the recommendations of the field offices of the USGS and BLM of tracts to be included in the sales were never made public, they could not have influenced the bidding. However, since industry interest was focused on these better tracts, it indicates that the better prospects are more often identified by several firms. The marginal, more risky prospects are detected by few firms or only one firm.

The bidding distributions in Alaska OCS lease sales indicate that areawide leasing has not affected competition in those sales. Three sales have been held in the planning areas in the Bering Sea: Sale 57 in Norton Basin in 1983, Sale 70 in St. George Basin in 1983, and Sale 83 in Navarin Basin in 1984. Each of these sales were the first sales ever held in these planning areas. The Norton and St. George sales were tract selection sales offering 418 and 478 tracts respectively, while the Navarin sale was an areawide sale offering 5,036 tracts. The percentage of tracts receiving three or more bids in the Navarin sale, however, was more than twice the percentage in either the Norton or St. George sale. Table 13 shows the bid distributions for those three sales.

Both the current estimates and the estimates made in 1982 of the resource potential of the Navarin Basin are higher than the estimates of potential for either St. George or Norton so the above distribution again suggests that higher potential tracts receive much greater competition than lower potential tracts.

The bidding in the Beaufort Sea again contradicts the hypothesis that areawide leasing has caused a significant increase in tracts receiving few bids. There is little difference in the bidding distributions for tract selection Sale 71 which offered 338 blocks in 1982 and areawide Sale 87 which offered 1475 blocks in 1984. Table 14 shows the bid distributions for those two sales. The three areawide sales in the Atlantic provide little evidence of the competitive effects of areawide leasing because there is currently limited interest in the Atlantic. Only 40 tracts received bids in Sale 76 in the Mid-Atlantic in 1983, only 11 tracts received bids in Sale 78 in the South

Table 12

Comparison of Bidding on Selected and Non-Selected Tracts
Gulf of Mexico First Areawide Sales

Sale 72

	Average bonus ($ million)	Percent 1-bid tracts
Recommended by both BLM and USGS	9.6	56
Recommended by neither BLM or USGS	4.7	71

Sale 74

	Average bonus ($ million)	Percent 1-bid tracts
Recommended by both BLM and USGS	6.3	44
Recommended by neither BLM or USGS	3.1	64

Sale 79

	Average bonus ($ million)	Percent 1-bid tracts
Recommended by both BLM and USGS	3.1	47
Recommended by neither BLM or USGS	1.3	84

Table 13

Distribution of Bids in Alaska OCS Sales

Number of Tracts (Percent)

	Norton (tract selection)	St. George (tract selection)	Navarin (areawide)
1 bid	44 (69)	63 (65)	85 (46)
2 bids	10 (16)	19 (20)	40 (22)
3 bids	6 (9)	11 (11)	23 (12)
4 bids	4 (6)	4 (4)	15 (8)
5 or more			23 (12)

Table 14

Distribution of Bids in Beaufort Sea Lease Sales

Number of Tracts (Percent)

	Sale 71 (tract selection)	Sale 87 (areawide)
1 bid	71 (57)	121 (52)
2 bids	24 (19)	52 (22)
3 bids	9 (7)	34 (15)
4 bids	7 (6)	20 (9)
5 or more	14 (11)	5 (2)

Atlantic in 1983, and no bids were received at all for the proposed Sale 82 in the North Atlantic in 1984. Factors such as moratoria, threat of litigation, and the Canadian boundary dispute also contributed to the lack of interest in Sale 82.

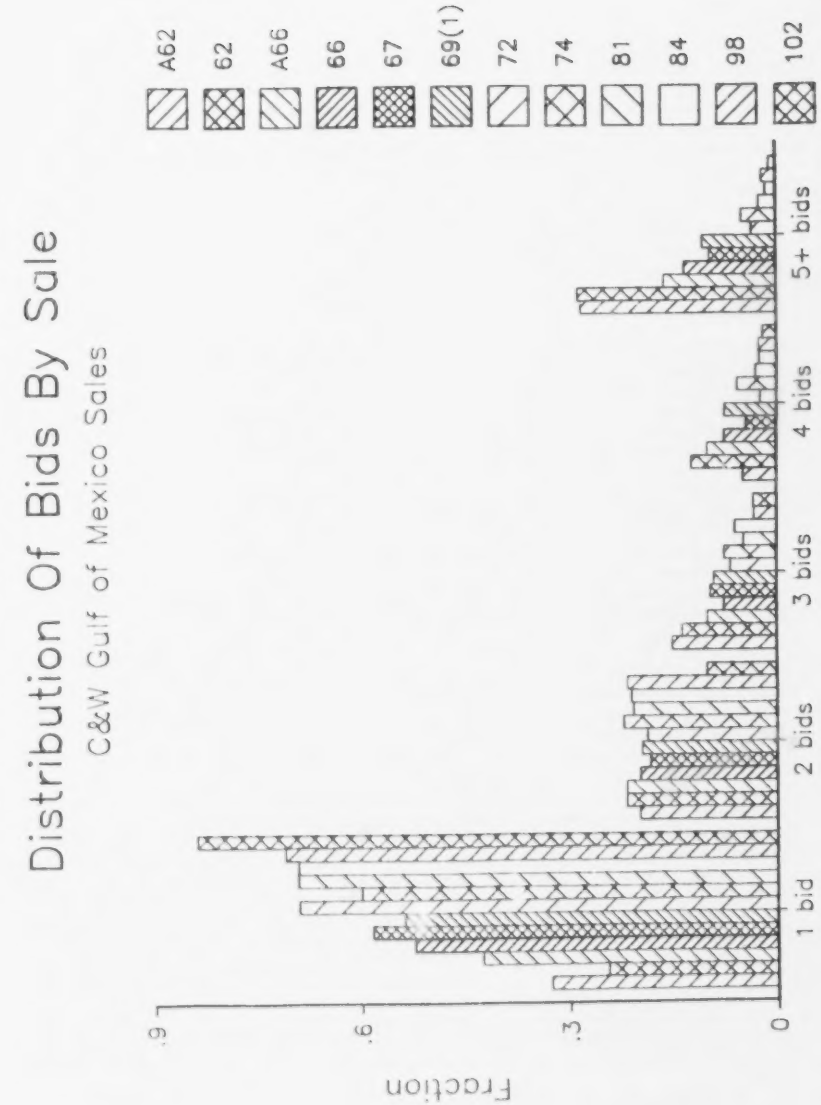
The Gulf of Mexico lease sales provide the best evidence of the relationship between the number of bids on OCS tracts and their value. Figure 4 shows the average value (high bid amount per tract) at each level of competition for the sales from A62 in 1980 through 102 in 1985. If a thinning of competition caused by areawide leasing was the dominant cause of lower bids, then one would expect to find a substantial decline in amounts of bids on tracts receiving fewer bids with the implementation of areawide leasing, while tracts receiving more bids kept their value.

As Figure 4 shows, however, the relationship between the number of bids and the amount of the high bid does not follow this pattern. Instead, the value of the tracts receiving a relatively high number of bids (5 or more) has been declining since the peak in late 1980 despite the evident intensity of competition. The 4- and 3-bid categories also show declines that began well before areawide leasing began. The amounts bid on 1- and 2-bid tracts have declined somewhat as well, but not nearly as much as the 5-or-more-bid tracts. It is clear from Figure 4 that the resource and economic characteristics of the tracts leased in each bid category and each sale are affecting the high bids received, lowering the value of tracts in later sales even on tracts for which competition remains high.

The declining number of highly competitive tracts evident in Figure 5 is consistent with the drawdown of an inventory in a series of sales that tend to lease higher value tracts earlier. This is not to say that areawide leasing beginning in 1983 has had no effect on the patterns of competition. It does suggest, however, that a substantial part of the decline in average bids is caused not by a decline in the number of bids, but by a decline in the economic value of the leases being sold.

Figure 5 shows the change in patterns of competition for leases in Gulf of Mexico sales from Sale A62 in September 1980 through Sale 102 in August 1985. It is clear from the one-bid bars and those for four and five-or-more bids that there has been a shift, increasing the fraction of tracts receiving only 1 bid and decreasing the fraction of tracts receiving four or more bids. This trend, however, does not begin with the first areawide sale, Sale 72. It begins two years earlier in 1981 with Sale A66. The increases in the fraction of one-bid tracts at the onset of areawide leasing are no more dramatic than those in 1981 and 1982 sales. These trends are consistent with a series of sales of declining quality properties in which the patterns of competition are strongly affected by the mix of tracts of different value being bid upon. Areawide leasing differed from tract selection leasing primarily by offering a greater number of moderate to low value tracts. However, declining oil and gas price expectations in 1981 and 1982, coupled with the leasing of over 2 million acres of prospects that tended to be above the average prospects in the Federal unleased inventory, reduced the number and value of the superior prospects remaining to be leased. If patterns of competition are strongly affected by the value mix of tracts offered, then the trend toward a mix of more moderate and low valued tracts with fewer and more moderately valued high value tracts would be consistent with the trends in competition shown in Figure 5.

Figure 5



For the third 5-year leasing program, the patterns of competition will be affected by the value mix of tracts offered. If areawide or tract selection procedures result in a similar mix of tracts because unleased prospects are ripening slowly, then competition is not likely to be very different.

Similarly, if areawide leasing is used and prospects ripen more quickly but are leased as they become worthy of investment, then tract values as a whole will not grow very great and competition will be similar to that resulting under conditions leading to slower ripening. Competition may be shifted toward higher numbers of bids on more tracts, however, if tract selection procedures are used and acreage is not offered until its value has appreciated substantially. The higher levels of competition achieved in this situation would tend to reduce reliance on the government's tract evaluations and build public confidence that fair market value was being received.

D. Statistical Analysis of Factors Affecting Competition and Bonuses

Earlier sections of this Appendix have presented a conceptual framework for assessing the private investment, Government revenue, and fair market value consequences of the pace of leasing. Additionally, factors affecting bonus bid and competition levels were presented and discussed. Data documenting some of these factors were presented in tabular and graphical form. While these techniques are useful for discerning trends and assessing the relationships between factors, they are less useful for measuring the independent effects of the many variables which are likely to influence competition levels and bonus bids. This section discusses a statistical technique for identifying the individual effects of these influences, as well as empirical applications of this technique to explanation of high bid and competition levels.

The fundamental issue is whether and to what extent the shift to areawide leasing in 1983 caused the decreases that have been observed in average bonuses and the average number of bids per tract. Statistical regression analysis is a well accepted method for measuring the extent to which such changes are associated with changes in a variety of other factors. When changes in variables measuring two factors are strongly related statistically and there is a logical, conceptual cause and effect relationship, then it is reasonable to conclude that one factor is the cause of the other. On the other hand, if the changes in different variables are not strongly related statistically or the conceptual basis for a cause and effection relationship is unclear, then less confidence is warranted that the factors are causally related.

On July 15, 1985, the U.S. General Accounting Office (GAO) released a report entitled "Early Assessment of Interior's Area-Wide Program For Leasing Offshore Lands." As part of this report, the GAO attempted to use regression analyses to determine whether the number of bids received for offshore tracts and their high bids have been affected by areawide leasing. The GAO report concluded that the number of bids per tract decreased by approximately 0.5 bids and the high bid per tract decreased by $3.1 million for "areawide" lease sales held during 1983 and 1984. This GAO estimated decline accounts for $541 of the total $2,624 per acre decline which the GAO found in the average high bids between the tract selection lease sales in the 1979-1983 period and the areawide sales in 1983 and 1984. On this basis, the GAO estimated that the

Treasury received $5.4 billion less in bonuses (present value discounted to 1984) than it would have received had the same tracts been leased more slowly. However, the discounting technique used by the GAO was improper and the $5.4 billion figure should actually have been only about $3.7 billion, according to Department of Energy calculations.

The GAO's regression analyses attempt to determine the effect of "areawide" leasing upon average high bid and number of bids per tract after adjusting for certain other factors which the GAO assumed were important in explaining the level of high bids and number of bids received per tract. The GAO assumed that variations in the level of the high bid for a given tract could be caused by the number of bids the tract received, the Government estimated value of the tract at or above the legal minimum bid level assigned by the Government, the price of foreign crude oil, the bidding system used (fixed royalty, sliding scale royalty, or fixed net profit share), the type of tract (wildcat, proven, drainage, or development), the percent of joint bids received on the tract, the location of the sale, the interest rate on triple-A bonds, and annual "dummy variables" (variables which take on the value of "one" if the event occurs and "zero" otherwise) for the years 1980 through 1984. The GAO uses the same variables to analyze variations in the number of bids which a given tract receives.

The GAO's statistical equations using these variables account for less than 25 percent of the observed variation in the number of bids received per tract and only about 35 percent of the observed variation in the high bid received per tract. Thus, GAO's analyses (including their assumption that "areawide" leasing effects the number of bids received and the level of the high bid) explain only a minor portion of the causes of declines in the number of bids and the level of the high bid per tract which have occurred since 1980.

In letters of August 27, 1985, to Congressman Dingell and September 30, 1985, to Congressman Jack Brooks, et. al., the Minerals Management Service (MMS) detailed a variety of deficiencies in the GAO's analyses. These deficiencies can be classified as general theoretical and modeling problems and data problems. The sum total of these deficiencies leads to the conclusion that GAO's findings with respect to areawide leasing are incorrect and misleading.

It is useful to examine the issues raised in the GAO report from a broad perspective to assess the degree of confidence merited by the GAO model. It is clear that bonus bids per acre have declined. As Figure 4 shows, that decline began in 1980, well before the implementation of an areawide leasing approach. Contributing to that decline were reductions in oil company projections of both short- and long-term energy prices; increases in exploration, development and production cost expectations as tracts have been leased in deeper waters, farther from shore, or in more hostile operating conditions; and the decline in geologic prospectiveness of tracts as better prospects become leased and those remaining are smaller, more subtle and more risky. How companies view these changes (and each clearly views them differently) is not really known by the Government or by the GAO. The range of estimates of these variables is likely to be so large as to swamp a refined analysis attempting to quantify relationships to the bids submitted, even if done correctly.

The problems confronted in performing statistical analysis with highly uncertain data are illustrated by the GAO's reliance upon tract value estimates made by the MMS for bid acceptance reviews. These estimates are made by MMS professionals using a substantial amount of professional judgment about a wide variety of economic and geologic factors including those mentioned above. The price expectation assumptions in Table 11 show that the MMS professionals over the past several years systematically overestimated future prices compared to what they would project today. If many companies, when they were bidding, had lower price expectations than did the MMS, that one factor alone would change the results of GAO's entire analysis. Similarly, it has been suggested that industry may have been too optimistic in its assessment of geological potential in the 1979-82 period and thus may have overbid during that period. That optimism has been brought down to earth by the long string of exploration failures offshore the Atlantic and Alaska coasts. In general, it is difficult to make sweeping judgments about the causes of changes in bonus levels, and one should not ascribe too much confidence to attempts at precision when the basic data is subject to great variation and error which has not been measured.

General theoretical and modeling problems present in the GAO's analyses include the failure to develop an explicit theoretical framework for the issue it seeks to analyze, the failure to recognize the highly nonlinear relationship between the real high bid and the number of bids received, and the inclusion of "dummy variables" which mask and confound the determination of individual relationships.

The lack of a theoretical framework leads to the specification of regression equations which do not consistently reflect the many factors that can affect bonus levels. For example in the GAO analysis, variables are included in the regression model to indicate whether sliding scale or fixed net profit share bidding systems were used rather than a fixed royalty bidding system. The use of these alternative systems yields different outcomes regarding the distribution of economic rents paid to the Government in the form of cash bonus and contingency payments and therefore may be expected to affect the level of the high bid and/or the number bids received. Although the different royalty rates used on leases issued under the fixed royalty system also affect the distribution of economic rents to the Government in the same way, the effects of these different royalty rates are not reflected in the GAO analysis. Additionally, the impact of the sixfold increase in the minimum bid level for Sale 71 in 1982 and subsequent sales (from $25 to $150 per acre) is not accounted for in the GAO's model. Omission of variables which sound theory would indicate should have been included in the GAO's model may have lead to biased estimates of the effects of areawide leasing.

The regression analyses presented in the GAO report assume that the high bid and the number of bids are linearly related. It is well known from bidding theory, however, that the relationship between the high bid and the number of bidders is highly nonlinear. Failure to recognize this theoretical constraint would cause an overestimate of the impact of changes in leasing rate upon bonus bid levels.

The GAO report[1] implies that GAO views the bidding process as occuring in separate steps. In particular, GAO apparently assumes that a firm will take the expected level of competition into account when formulating its bid amount, but that the magnitude of this bid amount will not effect the decision to participate. This apparently has led the GAO to develop a regression analysis in which the magnitude of the high bid has no effect upon the number of bidders. The GAO proceeded to estimate these relationships using a technique known as ordinary least squares (OLS). If the GAO's assumption that the level of the high bid does not affect the number of bids is correct and if the GAO's analysis did not omit variables from their model which significantly affect both the level of the high bid and the number of bids received per tract, then an OLS approach would be warranted. There is a good reason to believe, however, that the results of the lease auction process do not fulfill either condition.

First, as mentioned previously, the GAO's lack of a theoretical development has apparently led to the exclusion of relevant variables from the GAO's regression equations. Second, some portions of bidding theory imply that the number of bidders depends, in part, upon the perceived value of a tract while the level of the high bid also depends upon the number of bids. These theories state that the observed results of an auction are determined, at least in part, by the entry of more bidders up to the point at which the average profit expected by a bidder declines to a level that is insufficient to attract additional bids.[2] If this holds for OCS bidding, then the results of GAO's analyses based on the assumption that the number of bids does not depend on the value of the tract would be biased. The presentation of additional results in the GAO report[3] which purportedly take into account the two-way interaction between the level of high bid and the number of bids indicates that the GAO may have been aware of the expected bias in their OLS results. Unfortunately, these results have no meaning due to an apparent misapplication of the analytical technique used (known as "two stage least squares"). In particular, the problem is known in econometric theory as that of underidentification, i.e., the observations do not permit the measurement of the relationships that are assumed because the relationships do not include factors unique to the individual relationship.[4] Since the equations are underidentified, the estimates are invalid.

[1]GAO, Early Assessment of Interior's Area-Wide Program For Leasing Offshore Lands, July 15, 1985, Table 3, p.60.

[2]See for instance, Gaskins, D. W., Jr., and Teisberg, Thomas J. 1976. "An Economic Analysis of Pre-Sale Exploration in Oil and Gas Lease Sales." In Essays on Industrial Organization in Honor of Joe S. Bain, edited by Robert T. Masson and P. David Qualls, pp. 241-258. Cambridge, Mass.: Ballinger Publishing Co.

[3]GAO, Early Assessment of Interior's Area-Wide Program For Leasing Offshore Lands, July 15, 1985, Table 4, p. 61.

[4]For a basic introduction to the topic of identification, see for example, Walters, A.A., An Introduction to Econometrics. New York: W.W. Norton & Company, Inc.

A further problem in GAO's model results from the wholesale inclusion of "dummy variables" (those which take on the value of "zero" if a given condition is not present and a value of "one" if the condition is present) without theoretical justification. Inclusion of such variables can mask and confound the determination of individual relationships. This is especially evident in the relationships between the "Area-Wide" dummy variable and the annual dummy variables for the years 1980-1984. The reasons for including annual dummy variables is not clear. Apparently, GAO attemped to account for general macroeconomic changes that may have occurred year to year. If this is in fact the reason, the objective could have been handled directly by including such variables as Gross National Product or Gross Domestic Investment, future price expectations, or other indicators of the economic conditions which theory showed to affect competition or bid levels. However, with dummy variables included instead, the mathematics of the model allow for a variety of valid interpretations of these annual dummy variables. For example, the coefficient of the annual dummy variable for 1984 can just as appropriately be interpreted as measuring the marginal effect of 1984 areawide lease sales. The GAO report's conclusions are extremely sensitive to the specification of these annual dummy variables.

The confounding effect of wholesale inclusion of dummy variables is easily shown. The results of the statistical analyses reported for GAO's base case indicate, other things being equal, that the areawide sales in 1984 received an average of about 1.45 (1.97 - 0.52) more bids per tract than did the tract selection sales in 1979. In fact, the conclusion to be drawn is that only two small tract selection sales in Alaska, held in 1983, received more bids per tract on average, after adjusting for other factors, than did the areawide sales of 1983 and 1984. GAO, however, chooses to look only at the coefficient of the "Area-Wide" dummy variable and concludes that the number of bids has fallen.

There are two classes of conclusions to be found in the GAO report. The first class is based upon equations in which the GAO included the year in which the sales were held as a "dummy" variable in their statistical analyses (the base case and specifications 1, 2, 4, and 6). From this class, the GAO concluded that areawide sales reduced competition. However, these equations equally support the conclusion that sales in 1983 and 1984, the only years in which areawide lease sales were held, had more bids per tract and generally higher bonuses per acre, after adjusting for the other factors in their analysis. The GAO fails to provide either a theoretical framework or a rationale to explain or justify such a large divergence in possible conclusions.

The second class of conclusions is based on those equations in which the GAO did not include the year of the sale as a "dummy" variable (specifications 3 and 5). These equations show no statistically significant relationship between areawide leasing and the level of bonus bids or the number of bids received and, therefore, indicate that there was no bonus loss.

The second general category of deficiencies regarding the GAO regression analyses is data problems. These include the use of data from a censored sample of tracts, errors in variables, and the improper systematic exclusion

or inclusion of data. For example, bidding data on all wildcat and proven tracts which receive three or more valid bids and on tracts determined to be nonviable were excluded from GAO's data set. In addition, the GAO included other data which properly should be excluded such as data for tracts with high bids that were rejected. These data problems would be expected to produce a major bias in the analytical results.

The censored sample problem arises because high bids are observed only for tracts receiving bids. Although this fact is obvious, it is not a trivial problem. The set of tracts for which the high bid and the number of bids is recorded is the result of a sample selection rule which leads to biased estimates if not corrected. In a censored sample, the adjustment requires including an additional variable for the conditional probability of observing the data given the selection rule for submitting bids. GAO did not attempt this correction.

The errors in variables problem can be illustrated in relation to the estimates of tract values which are made by the MMS. The data used by the GAO truncates tract values (at the minimum bid level of either $25 or $150 per acre), but nevertheless uses it as a proxy for the value of the tract as perceived by the high bidder. Presumably, the untruncated estimate of tract value generated by the MMS is a random draw from the same distribution as that of the firm. The untruncated estimate of tract value generated by MMS is often a negative value, which is inconsistent with observed bids. Under these circumstances it is not clear that the truncated MMS estimates of tract values are a consistent proxy for the firms' tract values. If the errors in variables problem is not corrected, the GAO's OLS estimates will not only be biased but will also be inconsistent.

The final data problem to e discussed deals with the systematic exclusion from the GAO analyses of data which should e excluded. Tract value data for nonviable tracts and proven and wildcat tracts receiving three or more adjusted bids in areawide sales are not available for inclusin in GAO's analyses. This is a problem which can lead to extremely biased statistical estimates especially when the form of the equatin is misspecified. As shown in the previous section, the value of the high bid is a nonlinear relationship. The omission of proven and wildcat tracts receiving three or more adjusted bids from the analyses would be expected to yield estimates that overstate the impact of the areawide leasing on the number of bids. Similarly, by systematically omitting nonviable tracts (those judged by MMS to have a very low value, if any) the GAO analysis further biases the estimates since more of these nonviable tracts were bid upon under the areawide system than in tract selection sales. As part of MMS's review of the GAO's analyses, the MMS has estimated that certain corrections for the problems associated with missing data for proven and wildcat tracts receiving three or more adjusted bids and nonviable tracts can reduce the magnitude of the "effect of areawide leasing" on the number of bids by 80 percent and render this "effect" statistically nonsignificant.

The GAO's analyses also include observations for several hundreds of tracts whose high bids were rejected. Since GAO uses the results of its analyses to measure "bonus reduction" if any, due to the actual leasing of tracts under the areawide program, it is inappropriate to include in their analyses tracts which were not leased.

The conclusion from this review of GAO's analysis and from independent efforts to perform statistical analysis of areawide leasing is that conventional regression techniques, given the available data, yield little or no convincing evidence that the implementation of areawide leasing was a substantial cause of the observed decline in competition and bonus levels.

APPENDIX Q

POSTLEASE PROCESS, REGULATORY PROGRAM AND PERFORMANCE RECORD

POSTLEASE PROCESS, REGULATORY PROGRAM, AND PERFORMANCE RECORD

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I. INTRODUCTION

This appendix presents a normal course of action which a lessee would take after acquiring an Outer Continental Shelf (OCS) lease, assuming that hydrocarbons are discovered and produced. The steps from preliminary activities through exploration, development, and production to lease relinquishment are identified and described in terms of the regulatory requirements governing them. The inspection and enforcement program also is discussed, and the performance record of postlease operations is examined by identifying significant mishaps, i.e., blowouts and oil spills, which have occurred under the established regulatory program.

A brief explanation of the regulatory framework is necessary before discussing the postlease process. Broad authority pertaining to oil and gas leasing and development is set forth in the OCS Lands Act, as amended. Regulations promulgated under the OCS Lands Act which pertain to postlease operations are at Title 30, Part 250 and Part 256, Subpart N of the Code of Federal Regulations (CFR). The requirements set forth in the law and regulations are defined more specifically by OCS Orders, which provide detailed guidance pertaining to particular activities and operations. Regulatory requirements may also be set forth in lease instruments and stipulations.

Several other laws apply to the postlease process, including: The National Environmental Policy Act, as amended; Coastal Zone Management Act of 1972, as amended; Federal Water Pollution Control Act Amendments of 1972; Rivers and Harbors Act of 1899; Ports and Waterways Safety Act, as amended; Endangered Species Act; Fish and Wildlife Coordination Act; Marine Mammal Protection Act of 1972; Historic Preservation Act of 1966, as amended; and Archeological and Historic Preservation Act of 1974. The Minerals Management Service (MMS) consults and coordinates with the bureaus and agencies which are primarily responsible for implementing the pertinent provisions of these laws. In many cases, Memoranda of Understanding and Agreement have been drafted to clarify responsibilities and facilitate their execution.

II. POSTLEASE PROCESS AND REGULATORY PROGRAM

A. Preliminary Activities

Oil and gas activities on a lease begin with the lessee's acquisition of the information necessary to compile a comprehensive exploration plan. These "preliminary activities," prescribed by the MMS at 30 CFR 250.34-1, are operations which entail no more than very shallow penetration of the seabed and which do not affect significantly the natural resources of the Outer Continental Shelf (OCS). No other activities may be conducted on the lease until an exploration plan is submitted by the lessee and approved by the MMS.

The above cited regulation requires the lessee to include in the exploration plan certain standard descriptive information pertaining directly to operations as well as other relevant information. The collection of this other relevant information is accomplished by conducting preliminary activities. The type and extent of relevant information that may be required depends on the characteristics of the specific lease area. Special aspects of the proposed drilling site such

as geology, hazardous conditions, ecology, oceanography and meteorology, cultural resource potential, and multiple-use of the area might have to be addressed.

The requirement to address one or more of these lease characteristics may be set forth by the MMS at the prelease stage by attaching a stipulation to the lease or it may come about as a result of postlease review conducted by the MMS office overseeing the lease. The need to consider a specific issue also could arise from a biological opinion issued as a consequence of required consultation on lease sales with the Fish and Wildlife Service or National Marine Fisheries Service pursuant to the Endangered Species Act. Such an opinion may require that certain actions be taken or prevented and certain information be collected so as to avoid jeopardizing species identified as threatened or endangered.

Guidelines developed by the MMS office overseeing the lease, usually issued in a Notice to Lessees and Operators, detail the manner in which this required information is to be collected and the format in which it is to be submitted to the MMS for review. For example, such guidelines might specify the type of geophysical instrumentation to be employed in conducting a required shallow hazards survey, the navigation system to be used while collecting the data, and the type of processing which the collected data are to undergo before they are submitted. The issuance of such guidelines serves to clarify the requirements set forth in rules, lease stipulations, and biological opinions, so that lessees operating in a particular region will know exactly how to conduct preliminary activities and collect the information necessary to compile a comprehensive exploration plan.

B. Exploration Plan and Related Information

1. Contents

After completing preliminary activities, the lessee submits to the MMS an exploration plan which describes the proposed drilling site(s) and the planned exploratory operations. The plan may apply to one or more leases held by the lessee or to a group of unitized leases.* The following components comprise the package of information which the lessee is required to submit:

Exploration Plan

The regulation at 30 CFR 250.34-1 requires the exploration plan to describe: the proposed type and sequence of exploration activities and a timetable for their execution; the proposed drilling unit; the geophysical equipment to be used; the location of each proposed well; and the structure and formations expected to be drilled. Additional information may be required by each Region's OCS orders.

* Unitization entails combining two or more leases in a joint effort to explore, develop, or produce the unitized area more efficiently. The ultimate purposes served by unitization are prevention of waste, conservation of natural resources, and protection of correlative rights to production.

- Oil Spill Contingency Plan

OCS Order No. 7 requires submission of this plan.* It includes: provisions to assure that full resource capability can be committed to contain and clean up a spill; provisions for varying degrees of response depending on spill severity; provisions for protecting areas of special biological sensitivity; procedures for timely notification of all principals involved in oil spill containment and clean up; and provisions for special actions to be taken after discovery and notification of an oil spill.

- Critical Operations and Curtailment Plan

OCS Order No. 2 requires that this plan be submitted with the exploration plan. It identifies the operations to be conducted on the lease which are considered critical with respect to well control, fire prevention, and prevention of oil spills and other discharges and emissions. The plan also describes the circumstances or conditions under which such critical operations shall be curtailed. For example, a critical operation such as drill stem testing would be identified as impermissible when a certain limit of vessel motion is exceeded due to rough sea conditions.

- Hydrogen Sulfide Contingency Plan

This plan is submitted in accordance with OCS Order No. 2 when proposed drilling operations are expected to penetrate formations which are not known to be free of the poisonous gas hydrogen sulfide. It details specific plans for maintaining safety if hydrogen sulfide is encountered. MMS Standard OCS 1 governs operations conducted in a hydrogen sulfide environment and provides lessees guidance in preparing contingency plans for such operations.

- Environmental Report**

The environmental report is submitted in accordance with 30 CFR 250.34-3. It is not considered a part of the exploration plan, but accompanies the plan throughout the review process. It is a summary of environmental information which cites any pertinent newly developed site specific data not covered in the exploration plan or prelease environmental impact statement. The environmental report includes information on the exploration proposal which pertains to: personnel, supply and service needs and their impacts on the local community; air and sea travel between onshore and offshore facilities; solid and liquid discharges and air emissions; environmentally sensitive or potentially hazardous areas; and anticipated direct effects on the environment.

* In the Central and Western Gulf of Mexico OCS planning areas and in the Channel Islands area off California, exploration plans may incorporate a previously submitted Oil Spill Contingency Plan.

** Not required for leases in the Central and Western Gulf of Mexico OCS planning areas.

- Certification of Consistency with Coastal Zone Management Program(s) of Affected State(s)

In accordance with 30 CFR 250.34 and 15 CFR 930, a consistency certification must be submitted for each affected State having an approved management program pursuant to the Coastal Zone Management Act, as amended. The lessee identifies all activities described in its exploration plan which are subject to review by each State's management program. The lessee then certifies with a direct statement that these activities are consistent with provisions of the management plans of all affected States.

2. Review and Approval (see Figure 1)

a. Completeness Review and Distribution

The first step in MMS' analysis of the exploration plan is a completeness review to determine that all of the required information described above is included. Once it is deemed complete, the MMS distributes the exploration plan (excluding proprietary information) to affected States and to Federal Agencies such as the Environmental Protection Agency, Department of Defense, Fish and Wildlife Service, National Marine Fisheries Service, Army Corps of Engineers, Coast Guard, and Office of Coastal Resource Management. Copies also are made available to the public.

b. Technical Review

The exploration plan undergoes a thorough technical analysis by MMS engineers and scientists. Much of this review addresses the equipment planned for use in the exploratory drilling operations. The fitness of the drilling facility to perform the proposed operations is examined* with a focus on the rated capacities of all drilling equipment, safety systems, firefighting equipment and pollution prevention equipment. Proposed new or unusual technology receives special scrutiny, and all equipment is evaluated in light of the best available and safest technologies standard mandated by section 21 of the OCS Lands Act, as amended.

Geological and geophysical aspects of the plan also are analyzed. This analysis concentrates on types of geophysical equipment to be used, the well-logging program, proposed well locations, potential geohazards, and cross sections of marker formations.

The oil spill contingency plan, hydrogen sulfide contingency plan, and critical operations curtailment plan are reviewed for adequacy in light of the applicable OCS Orders. The U.S. Coast Guard also conducts a technical review of oil spill response and cleanup equipment procedures in accordance with a Memorandum of Understanding executed in 1981.

* Drilling facilities such as artificial islands used for exploratory drilling in the Alaska OCS Region are subject to review under the Platform Verification Program described on page Q-16.

c. Environmental Review

The regulations at 30 CFR 250.34-4 outline the MMS' duty to comply with the National Environmental Policy Act (NEPA) by conducting an environmental review of the proposed operations. Environmental scientists conduct this review, drawing on the information in the environmental report and other documents, comments prepared by staff as a result of their technical review, and the comments of affected States, Federal Agencies, and other interested parties. This review gives particular attention to: facilities proposed for installation in areas of high seismicity; facilities proposed for installation within areas of high ecological sensitivity; the use of bottom founded facilities in areas of potentially hazardous bottom conditions; and the use of new or unusual technology. For an exploration plan in the Alaska Region, the environmental review includes an evaluation of effects on subsistence uses that could occur from exploration, as required by court cases interpreting section 810 of the Alaska National Interest Lands Conservation Act (ANILCA).

Environmental review of the exploration plan results in a finding of no significant impact or a finding that approval of the proposed operations constitutes a major Federal action significantly affecting the quality of the human environment. A finding of no significant impact may be documented by a categorical exclusion review or an environmental assessment. The former procedure examines the exploration proposal in light of an established category of actions which do not have a significant effect on the human environment and for which neither an environmental assessment nor environmental impact statement is required. An environmental assessment briefly discusses the exploration proposal in terms of environmental effects and provides the basis for determining whether to prepare a finding of no significant impact or an environmental impact statement. If it is concluded that approval of the exploration plan is a major Federal action significantly affecting the quality of the human environment, an environmental impact statement will be prepared.

d. Coastal Zone Management Consistency Review

Each affected State having an approved Coastal Zone Management Program is given a maximum of 180 days to review the exploration plan for consistency with its program. Within 90 days after receipt of the plan by the State agency administering the management program, written concurrence or objection to the proposed operations (or a status of review and basis for further delay) is submitted to the MMS by the State agency. The State agency's concurrence with the consistency certification is conclusively presumed in the absence of any written communication to the MMS by that agency.

e. Approval or Disapproval

Within 30 days after the exploration plan has been deemed complete, the MMS must approve it, require modification of it, or disapprove it. The plan is approved if it conforms to the provisions of the

lease, the OCS Lands Act, and the regulations. Modification of the plan is required if it does not conform to these provisions. The plan is disapproved if it is decided that the proposed operations probably would cause serious harm or damage to life (including fish and other aquatic life), property, any mineral (in areas leased or not leased), the national security or defense, or to the marine, coastal, or human environment.

Once the MMS approves the exploration plan, consistency concurrence must be received from all affected States before operations proposed in the plan may be permitted. If an affected State rules that the plan is not consistent with its Coastal Zone Management Program, the lessee may appeal to the Secretary of Commerce, who may uphold or reverse the State's findings in accordance with the provisions of 15 CFR 930.

C. Application for Permit to Drill (APD)

1. Contents

The lessee must submit and receive approval of an APD before commencing exploratory drilling operations. It must conform to the regulatory requirements of 250.36 and the more specific requirements of OCS Order No 2. Information required in the APD includes:

- Exact surface and bottom hole location of the proposed well(s), elevation of the derrick floor, and water depth;
- Projected depth of the well(s) and estimated depths at which encounters with water, oil, gas, and mineral deposits are expected;
- Proposed casing and cementing program, including size, weight, grade and setting depths of casing and the amount of cement to be used; and discussion of formation fracture gradients, formation pressures, and anticipated surface pressures;
- Description of the blowout-prevention equipment, including pressure ratings;
- Description of the drilling mud program, including table of well depth versus minimum quantities of mud material to be on hand to assure well control; and
- Logging and coring program.

2. Review and Approval (see Figure 1)

The APD is reviewed by the MMS office charged with overseeing the lease. All of the information listed above is analyzed by engineers and scientists to establish the safety and environmental soundness of the proposed drilling program.

EXPLORATION PLAN REVIEW

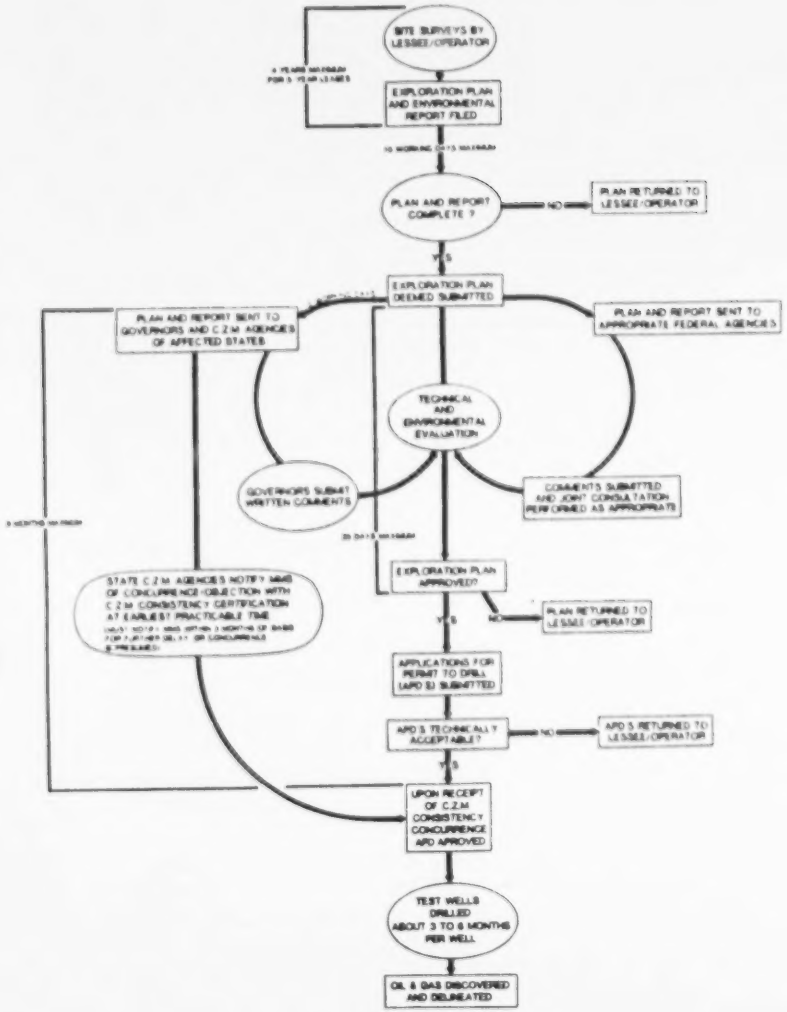

FIGURE 1

Structure maps and cross sections are analyzed for accuracy, and if correlating well logs are available, they are reviewed to glean lithologies and formation pressures that may affect well control. The casing and cementing program is examined to verify conformance with the requirements of OCS Order No. 2, which are designed to maintain safe well conditions and protection of the environment, including freshwater aquifers. Formation fracture gradients, formation pressures, and anticipated surface pressures are scrutinized in light of planned casing setting depths, mud weights, and blowout-prevention equipment, respectively. The mud inventory is checked to verify that sufficient quantities to maintain well control will be readily available. The Welding, Burning and Hot Tapping Plan is reviewed to assure that safe and environmentally sound procedures guiding these activities will be established and followed at the drilling location. Descriptions of well control and pollution-prevention equipment also are examined, as is other required information, including that addressing regional or lease specific criteria.

Based upon this review, the APD is either approved or returned to the lessee for modification. When it is approved, conditions of approval are attached which provide specific directions pertaining to the proposed well(s). These conditions are founded on the regulations and OCS Orders, and do not add regulatory requirements.

As previously stated, the APD may not be approved until all affected States concur (or are conclusively presumed to have concurred) with the lessee's certification of consistency with approved Coastal Zone Management Programs. The approved APD and other Federal permits are required before actual drilling may commence. Other permits include: Coast Guard aids to navigation and certification of mobile offshore drilling unit; Corps of Engineers navigation permit; and Environmental Protection Agency permit for discharging in accordance with the National Pollutant Discharge Elimination System.

D. Exploratory Operations

1. Drilling

Once all necessary permits have been obtained, the lessee will place a drilling facility on the leasehold to commence operations. This facility will undergo a thorough inspection by the MMS prior to being put into operation if it is a new facility or if it has not been used previously in the same OCS region. The type of facility (mobile offshore drilling unit, platform, artificial island) is chosen based on consideration of conditions at the wellsite such as water depth, bottom conditions, and oceanographic and meteorological phenomena.

The exploration project is serviced by an onshore base from which supplies and personnel are sent to the wellsite. Supplies such as drilling mud and equipment usually are sent by boat. Personnel and delicate equipment usually travel by helicopter to the drilling location, which in most cases is equipped with landing and refueling facilities. MMS personnel also fly to the wellsite to perform required periodic inspections of the operations.

Drilling operations are governed by 30 CFR 250 and OCS Order No. 2. The lessee's exploration plan and application for permit to drill and conditions of approval provide additional guidance. These rules and conditions require the following:

- Installation and periodic testing of pollution-prevention equipment;
- Directional surveying at certain depths to record data used to determine the horizontal variation in the location of the wellbore;
- Meeting prescribed casing standards; placing, cementing, and testing casing prior to drilling below specified depths;
- Maintaining proper mud condition to assure well control;
- Training and qualification of drilling personnel;
- Keeping continuous supervision and surveillance of the drilling rig with qualified personnel; and
- Performing specified operations in accordance with the Critical Operations and Curtailment Plan.

The objective of exploratory drilling is to collect information which indicates the potential of the drilled structure to produce hydrocarbons in paying quantities. Well cuttings churned up by the drill bit and carried to the surface by drilling mud are a source of useful information. Sophisticated information is obtained by running logging instruments down the well, and coring is done to acquire large pieces of penetrated formations. All of this information is analyzed to ascertain formation character in terms of paleontology, stratigraphy, permeability, and porosity, which are key indicators in the search for hydrocarbons. When the presence of oil or gas is indicated, the lessee usually performs tests which measure flowing pressure and determine fluid content.

The MMS monitors exploratory drilling operations to ensure that the lessee conforms to laws, regulations, and provisions of the lease and operates in a manner consistent with its approved exploration plan and drilling permit. The drilling unit is periodically inspected, drilling reports are required to be submitted periodically, and certain operations (identified at 30 CFR 250.92) may not be performed by the lessee without written approval of a well Sundry Notice. Also, the MMS has access to all information acquired by the lessee and may conduct its own analysis of the well.

2. Plugging and Abandonment

After exploratory drilling is finished, the lessee plugs and abandons the well in accordance with 30 CFR 250.44 and OCS Order No.3. The MMS must approve proposed abandonment operations before they are undertaken,

and the lessee is required to file a subsequent report of completed work in a Sundry Notice. MMS inspectors witness abandonment operations when their schedules permit.

Cement plugs must be placed in the well and tested so that fluids cannot move to the surface or migrate between subsurface formations. The intervals between these plugs are filled with mud dense enough to offset formation pressures. Also, drilling equipment and paraphernalia must be removed from the seafloor, and the lessee documents site clearance to the MMS.

3. Determination of Well Producibility and Suspension of Operations

The lessee is required by OCS Order No. 4 to submit to the MMS an application for determination of well producibility within 60 days after abandoning the well and moving the drilling rig off location. This application must be made for every well drilled on a lease until one is determined to be capable of producing oil or gas in paying quantities. The MMS makes this determination for each applicant well based on analysis of well information such as flowtest data, coring reports, and well logs.

If the MMS determines that hydrocarbons in paying quantities have been discovered, the lessee may use this determination as a basis for requesting a suspension of operations on the lease pursuant to 30 CFR 250.12. A suspension of operations is a very useful device for lease development, as it allows the lessee to continue the lease in effect past its primary term while development activities are undertaken and until production commences. A suspension may be granted for up to 5 years to achieve certain purposes, including the following:

- facilitate proper development of the lease; and
- allow for construction of, or negotiation for the use of, transportation facilities.

Suspension requests are most commonly made for these two purposes, and they are considered in light of the provisions of 30 CFR 250.12 (and OCS order No. 14 in the Gulf of Mexico OCS Region). The MMS has established a policy requiring lessees who request such suspensions to submit a schedule of activities reasonably designed to lead to the commencement of production. This schedule and the determination that paying quantities of hydrocarbons exist on the leasehold are necessary for any suspension request to receive serious consideration from the MMS.

4. Delineation of Productive Area

Having drilled one exploratory well on the lease, the lessee's next step depends on the results of that well. All of the information acquired from the well is analyzed, and a decision is made as to whether further drilling on the leasehold is warranted. If the first well failed to encounter oil or gas in paying quantities, the information acquired from the well may indicate that additional evaluation of the lease would

not be worthwhile or it may indicate that the search for hydrocarbons should continue at another site on the leasehold. When producible hydrocarbons are encountered, the lessee usually makes a prompt effort to determine the size and shape of the productive area by drilling additional wells. Each additional well must be described in an approved exploration plan, and drilling operations may not be conducted unless an application for permit to drill the well has been approved.

E. Development and Production Plan

1. Contents

After completing the drilling necessary to delineate the discovered productive area, the lessee is required to submit and receive approval of a development and production plan* before undertaking activities designed to lead to production from the leasehold. This plan is similar to an exploration plan and is subjected to an analogous review process. The development and production plan package to be submitted is composed of several components, which are listed below:

- Development and Production Plan

  The regulation at 30 CFR 250.34-2 requires the development and production plan to describe: all the work to be performed to achieve sustained production; all drilling vessels, platforms, pipelines or other facilities and operations; surface and bottom-hole locations of each proposed well; interpretations of all relevant geological and geophysical data; environmental safeguards to be implemented; safety standards and features; the expected rate of development and production; and other relevant information the MMS may require. Additional information may be required by each Region's OCS orders.

  The development operations coordination document that may be required in lieu of a development and production plan for leases in the Central and Western Gulf of Mexico planning areas contains only the information listed above which the MMS office overseeing the lease deems necessary to comply with provisions of the lease, laws and regulations. This document is subject to the same review and approval process as a development and production plan.

- Oil Spill Contingency Plan

  An oil spill contingency plan similar to that submitted with the exploration plan, but pertaining to the proposed development and production activities, must be submitted prior to or with the development and production plan in accordance with OCS Order No. 7.

Pursuant to 30 CFR 250.34-2(a)(2), a Development Operations Coordination Document may be submitted in lieu of a development and production plan for leases in the Central and Western Gulf of Mexico OCS planning areas.

- Critical Operations and Curtailment Plan

  A plan similar to that submitted with the exploration plan, but pertaining to the proposed development and production activities, must be submitted in accordance with OCS Order No. 2.

- Hydrogen Sulfide Contingency Plan

  If previous drilling has not proven that the formations to be drilled in developing and producing the discovered reservoir(s) are free of hydrogen sulfide, the lessee must submit a hydrogen sulfide contingency plan addressing the proposed operations in accordance with OCS Order No. 2.

- Environmental Report*

  The environmental report is submitted pursuant to 30 CFR 250.34-3 and contains environmental information not included in the development and production plan. This information includes: the location, description, and size of offshore and onshore operations and facilities; the land, labor, material and energy requirements of the proposed operations; a schedule of near-shore and onshore development activities entailed in the project; a description of environmental monitoring systems; a description of the contingency plans in effect for the activities; and a narrative description of the existing environment.

- Certification of Consistency with Coastal Zone Management Program(s) of Affected States

  The lessee must certify that the activities described in the development and production plan are consistent with provisions of coastal zone management plans of all affected States.

2. Review and Approval (see Figure 2)

   a. Completeness Review and Distribution

      The MMS first conducts a completeness review of the development and production plan and related information. Once deemed complete, a notice announcing receipt of the plan is published in the Federal Register, and copies of the plan (excluding proprietary information) are distributed to appropriate Federal Agencies, affected States, and affected localities for review. Copies also are made available to the public for review and comment.

* Not required for leases in the Central and Western Gulf of Mexico OCS planning areas

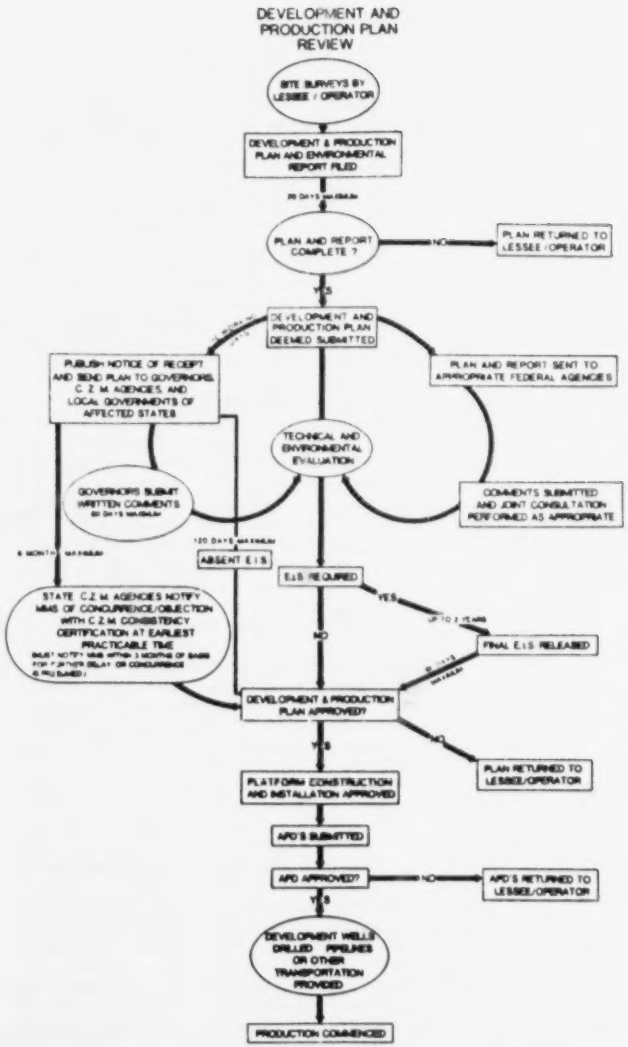

FIGURE 2

b. Technical Review

The development and production plan is analyzed by MMS personnel in a manner similar to exploration plan review. The soundness of technological and scientific information provided in the plan is determined, and intense scrutiny is applied to portions of the plan dealing with proposed safety and pollution-prevention equipment and procedures. The technical review processes for platform and transportation proposals, two major features of development and production activities, are explained separately later in this appendix.

c. Environmental Review

The development and production plan undergoes an environmental review governed by 30 CFR 250.34-4 which is similar to the one conducted for an exploration plan. This review also results in a finding of no significant impact or a finding of significant impact. When environmental analysis determines that permitting the proposed project would be a major Federal action significantly affecting the human environment which has not been considered adequately in a previous environmental impact statement, a new statement pertaining to the project must be prepared. Outside the Central and Western Gulf of Mexico OCS planning areas, approval of a development and production plan must be declared a major Federal action at least once.

An environmental review of proposed development and production operations includes an examination of the planned construction of new onshore facilities which could have significant adverse effects on the environment. It also gives special attention to the cumulative, previously unforeseen, and significantly different impacts which could result from the project. For a development and production plan in the Alaska Region, the environmental review evaluates the effects of proposed activities on subsistence uses, as required by court cases interpreting section 810 of ANILCA.

d. Coordination and Consultation with Affected Sates and Local Governments.

Section 19 of the OCS Lands Act provides for the Governor of any affected State and the executive of any affected local government to be given the opportunity to make recommendations regarding the development and production plan. Recommendations offered during this consultation process are accepted if they are determined to provide for a reasonable balance between the national interest and the well-being of the citizens of the affected States. Also, cooperative agreements may be formed by the Department of the Interior and affected States to facilitate efficient review and approval of development and production plans. For example, plans submitted for leases in California OCS planning areas may be subjected to a joint environmental analysis by the MMS and the State, generating an environmental impact statement/environmental impact report.

e. Coastal Zone Management Consistency Review

Each affected State having an approved Coastal Zone Management Program reviews the development and production plan for consistency with its program. The procedures governing this review are identical to those governing exploration plan review.

f. Approval or Disapproval

The MMS must approve, disapprove, or require modification of the development and production plan within timeframes set forth at 30 CFR 250.34-2. When an environmental impact statement must be prepared, a decision is required within 60 days after release of the final statement. Otherwise, a decision must be rendered within a maximum of 120 days from the date the plan is received by the Governors of affected States.

The plan is approved if it conforms to applicable laws, regulations, lease provisions, and environmental, safety and health requirements. It is required to be modified if it does not conform to such criteria. The plan is disapproved in the following cases: 1) an affected State finds it inconsistent with its Coastal Zone Management Program and that finding is not reversed or overruled by the Secretary of Commerce; 2) it is found to be a threat to national security or defense; or 3) it describes operations which would probably cause serious harm or damage to life (including fish and other aquatic life), property, or the environment.

All development and production operations to be carried out on the lease must be described in the approved development and production plan. Revisions to the plan may become necessary as the project progresses, and these must be proposed, reviewed, and approved in the same manner as the original plan.

F. Production, Processing, and Transportation Facilities

1. Platforms

The facility planned for use in developing and producing the discovered reservoir(s) is described in the development and production plan. Design and fabrication of a floating facility are reviewed and approved by the Coast Guard, and permitting installation of such a facility is the responsibility of the MMS. The MMS permits design, fabrication and installation of any fixed or bottom founded facility in accordance with OCS Order No. 8, with two separate programs established to guide the process:

° Platform Approval Program

The Platform Approval Program operates only in the Gulf of Mexico OCS planning areas. It applies to facilities of proven conventional design proposed for service in areas with stable bottom conditions and relatively calm waters less than 400 feet deep. This program and its

application criteria draw on the long and immensely safe record of platform installation and service in the Gulf of Mexico. Under the program, the lessee submits to the MMS an application certified by a registered professional structural engineer. The application is reviewed by MMS engineers to determine the structural soundness of the project, and approval or disapproval of the application is rendered based on their findings.

° Platform Verification Program

The Platform Verification Program operates in all OCS regions. It applies to all fixed and bottom founded production facilities proposed for use in the Atlantic, Alaska, and Pacific Regions. In the Gulf of Mexico, it applies to all facilities not covered by the Platform Approval Program. Briefly summarized, the program calls for independent technical reviewers approved by the MMS to analyze, design and monitor fabrication and installation of proposed facilities. These reviewers, certified verification agents, are contracted by the lessee to perform necessary analyses and inspections of the project and report their findings to the MMS. The MMS makes approval/disapproval decisions based on these reports and on information gained from actual MMS inspection of the project at the design, fabrication and installation stages.

2. Transportation

The oil and gas to be developed and produced ultimately will be transported to shore for processing and refining in the manner described in the development and production plan. Natural gas is carried to shore by pipeline, and oil may be transported by pipeline or by seagoing vessel. The means of transportation which the lessee decides to use for oil is dictated by economic and environmental considerations. For example, a small reservoir in deep water in a frontier area would probably lead the lessee to consider moving oil by tanker. On the other hand, a large resevoir in a commercially proven area of conventional water depth would induce construction of a pipeline to link to already existing infrastructure. Also, a lease stipulation may require the use of a pipeline as the safest and most environmentally sound means to carry oil from the leasehold.

The U.S. Coast Guard has responsibility for regulating the transportation of crude oil by vessel. All vessels engaged in OCS activities are subject to Coast Guard standards pertaining to: design, loading, fabrication and construction requirements; stability and buoyancy; modification and repair requirements related to structural integrity; and general arrangement. Additional Coast Guard requirements include those for training, drills, inspections, and emergency procedures with respect to transfer of petroleum and other products from or to a vessel. The applicable regulations are set forth in titles 33 and 46 of the CFR.

If the lessee intends to move produced oil and gas to shore with a pipeline, an application for the appropriate permit must be submitted to the MMS. A pipeline which is wholly contained within the boundaries of a single lease, unitized leases, or contiguous (not

cornering) leases held by one owner or operator is permitted under lease terms and in accordance with 30 CFR 250.20 and OCS Order No. 9. Such a pipeline which traverses lease boundaries outside the above described limits or crosses unleased lands is permitted through the issuance of a right-of-way in accordance with 30 CFR 256, Subpart N. The MMS does not have permitting authority for pipelines located in State waters, but does work with the affected State by providing a copy of the pipeline application under MMS consideration.

Overall regulation of pipelines is shared by the Department of the Interior and the Department of Transportation. The MMS, with its permitting program, has established requirements governing pipeline design, fabrication and installation calling for the use of best available and safest technologies as required by section 21 of the OCS Lands Act. The Department of Transportation regulations at 49 CFR 192 and 195 provide detailed safety rules and procedures pertaining to design, construction, operation, maintenance, and testing of pipelines. The division of responsibilities concerning OCS pipelines is spelled out in a Memorandum of Understanding which the Department of the Interior and the Department of Transportation executed in 1976.

The MMS reviews the lessee's pipeline application for consistency with the above referenced rules and lease provisions, including any special lease stipulations. The pipeline must be designed to withstand environmental conditions such as current scour, external corrosion, and ice movement (in the arctic), as well as the internal pressures, temperatures, and corrosive and erosive qualities of the transported fluids. The MMS also ensures that the planned pipeline will not pose an unreasonable obstruction to fishing and shipping operations, administering a policy calling for burial of pipelines in rights-of-way with water depths of less than 200 feet.

G. Development and Production Operations

1. Platform Installation

The platform from which the lessee will drill and produce the discovered hydrocarbons is installed in accordance with OCS Order No. 8. An installation verification plan must be submitted if the platform is covered by the Platform Verification Program. This plan discusses the technical details of the planned installation, names the certified verification agent, and describes the work the agent will do on the project. The platform is required to be installed in a manner consistent with the installation verification plan. If not covered by the Platform Verification Program, platform installation is governed by the Platform Approval Program.

2. Development Drilling

The drilling operations described in the lessee's approved development and production plan must be permitted by an approved Application for Permit to Drill. Also, operations common in development activities, such as deepening, side tracking, or plugging back an existing well, must be similarly permitted.

The content requirements and review procedures described above in Part C of this appendix also apply to an Application for Permit to Drill development wells.

Wells are then drilled to develop the discovered hydrocarbons. These wells usually are drilled directionally from one platform containing several slots arranged in rows to enable drilling operations to hit the various targets identified by the lessee for maximum efficient flow and recovery. Subsea (see floor) completions may be drilled and completed some distance away from a platform and connected to the platform through flow lines. All drilling operations are governed by 30 CFR 250, OCS Order No. 2, and permit conditions of approval, and they are monitored by MMS personnel.

3. Completion and Production Operations

a. Completion

Once each well is drilled to a productive target, the well is completed to enable actual production of the hydrocarbons. Completion operations entail placing production casing, tubing and packers, and wellhead equipment and perforating the production casing opposite the formation(s) to be produced. The production string of casing seals off the producing formation, the tubing and packers enable the well to flow to surface, and the wellhead seals the well at the surface to allow surface control of flow. Completions are governed by OCS Orders No. 2 and No. 6.

b. Production

(1) Safety Procedures and Equipment

The safety of production operations is guided primarily by OCS Order No. 5, which outlines requirements pertaining to general platform operations and to production safety systems. The latter are designed to prevent significant impacts on safety, health, and the environment from occurring during the course of producing oil and gas. All production safety systems must be installed and operated in accordance with the Order and its call for the use of best available and safest technologies. Production facilities are subject to a preproduction (startup) inspection, and each facility is inspected by the MMS at lease once per year thereafter.

(2) Measurement

Since a royalty on produced hydrocarbons is paid to the Federal Government, the lessee is required to measure accurately the volume produced, using equipment and procedures described in OCS Order No. 13. The lessee must submit and receive approval of an application describing the measurement system before actually commencing production. This application is reviewed by MMS staff in light of the requirements of OCS Order No. 13. Once it is

approved and production commences, the MMS periodically verifies the measurement of produced hydrocarbons as part of its field inspection program.

(3) Rate Control

To prevent waste and protect correlative rights to the reservoir, it must be produced at a rate proposed by the lessee and approved by the MMS pursuant to OCS Order No. 11. This maximum efficient rate is specific to each reservoir and is defined as the highest sustainable daily withdrawal rate at which the reservoir can be economically developed and depleted without detriment to ultimate recovery.

A maximum production rate, which applies to individual well completions rather than reservoirs, must be proposed and approved for each oil or gas completion in the reservoir. Establishment of this rate is based on information acquired from well tests. The sum of all maximum production rates for a reservoir may not exceed that reservoir's maximum efficient rate.

c. Servicing and Workover

The producing performance of the reservoir is monitored by periodically conducting flow tests. The results of these tests may indicate that well servicing and workover operations are necessary to restore full production capability. These operations entail repairs to production equipment and materials or alteration of the producing formation. The lessee must receive MMS approval of a detailed Sundry Notice of intent to perform such an operation before commencing it, and a subsequent report of the operation must be filed with the MMS when finished. A Plan for Conducting Simultaneous Operations, submitted and approved in accordance with OCS Order No. 5, governs servicing and workover operations when they are performed concurrently with production operations.

H. Lease Expiration and Abandonment

The lease continues in effect for an established primary term of 5, 8, or 10 years and as long thereafter as oil or gas is produced in paying quantities or approved drilling or well reworking operations are conducted to restore production. After the primary term has expired, a 90-day lapse on such operations in the absence of an approved suspension of operations will cause the lease to expire. When production ceases and further drilling and workover operations are determined to be unwarranted, the following actions become necessary:

1. Borehole Abandonment

The lessee must immediately abandon all boreholes in accordance with 30 CFR 250.44 and OCS Order No. 3. The procedure for abandoning these wells is the same as that described for exploration wells, except that abandonment of a formerly producing well always must be described in advance in a Sundry Notice. This written notification of intent to abandon must state the reason for abandonment as well as present the plan of work to be followed. Actual work may not begin until the Sundry Notice is approved by the MMS.

2. Platform Removal

Pursuant to the lease agreement, the lessee has one year to remove from the leasehold all structures, machinery, and other materials. There is an exception to this provision. If the structures are involved in operations on other leases, they may be left in place as long as they are useful to those operations. Also, an evolving new program may someday allow structures that have established themselves as artificial reefs supporting rich and varied biological resources to be left in place.

When the platform is removed, operations must be conducted in accordance with OCS Order No. 3, which requires the clearance of all piling and other material to a depth of at least 15 feet below the ocean floor. The lessee then must document to the MMS that the leasehold has been abandoned properly and is free of seafloor obstructions.

3. Pipeline Abandonment

If it is determined by the lessee or the holder of the pipeline right-of-way and the MMS that the pipeline will serve no purpose as a result of cessation of production from the leasehold, the right-of-way will be terminated. The pipeline must be properly abandoned, and any pipeline stations and associated equipment which might pose a hazard to navigation must be removed. The pipeline need not be removed but may be abandoned in place provided that such action does not cause unreasonable hazard to navigation, commercial fishing or the marine environment. The line is required to be purged of all petroleum products, and any open ends of the pipe must be plugged and buried to a minimum depth of 3 feet.

II. INSPECTION AND ENFORCEMENT

A. Inspection Program

The MMS performs onsite compliance inspections of OCS oil and gas operations in accordance with 30 CFR 250.11. The regulation requires each OCS facility to be inspected at least once a year and also calls for periodic unannounced inspections. Inspection policies and procedures are documented in the MMS Offshore Inspection Program Manual Chapter dated May 8, 1983, and their implementation is directed by the Offshore Inspection Program Handbook dated July 17, 1984. Field office supplements and instructions further define the policies and procedures of the inspection manual chapter.

A national inspection characteristics checklist, the potential incident of noncompliance (PINC) list, is used to carry out each inspection. It consists of regulatory requirements, including all safety and pollution-prevention requirements set forth in the OCS Orders, which are presented in the form of questions calling for yes or no answers. A negative answer to any question indicates an incident of noncompliance (INC), which is a violation of a regulatory requirement.

Drilling and production inspections are categorized as detailed or nondetailed. A detailed inspection is conducted at least annually on each production and drilling facility. In a detailed inspection, the entire PINC list pertaining to the activity (drilling or production) being inspected is used. In a nondetailed inspection, a portion of the applicable PINC list is used. The PINC's used in a nondetailed inspection are selected by reviewing past inspection data. Nondetailed inspections are unannounced, are done randomly in some cases, and are performed on problem facilities more often if warranted.

The frequency at which a facility is inspected depends on several factors. Facilities operating in frontier areas are inspected more frequently than those in mature areas, and a facility with a poor record in past inspections will be inspected more often than one with a good record. The Offshore Inspection System, an automated file of inspection results which is expected to be fully operational in April 1986, will provide pertinent data to be used in scheduling inspections. This system is a nationwide data base which will be used as a management tool in planning all aspects of inspections.

Inspections are carried out by petroleum engineering technicians who are based at a field office near the area of operations. A PINC list may be specifically developed for each inspection. An INC is issued to the operator for any violation detected, and each one elicits a prescribed enforcement action consisting of the issuance of a warning or a shut-in order. A warning generally is issued for any INC which does not jeopardize safety or have the potential to cause pollution, and the INC must be corrected within a prescribed period of time. A shut-in order is issued for more critical INC's, causing the cessation of a particular operation until the situation responsible for the INC is corrected. The shut-in order may apply to the entire facility or to just a part of the facility.

B. Penalties

The penalties which may be assessed to persons violating any provision of the OCS Land's Act or pertinent rules, regulations, leases, licenses, or permits are set forth at 30 CFR 250.80-2. Penalties include two types:

- Civil Penalties

  Civil penalties may be pursued for cases in which a lessee has violated a requirement and failed to correct the violation after being notified and given a reasonable time to correct it. For example, a lessee failing to correct an INC within the prescribed time would normally be assessed such a penalty. Anyone charged with such a violation is given the opportunity to present evidence at a hearing conducted in accordance with detailed provisions set forth at 30 CFR 250.80-1. If a civil penalty is actually assessed, it is in the form of a fine of up to 10,000 dollars for each day the violation existed.

- Criminal Penalties

  Criminal penalties are assessed in cases of knowing and willful violation of certain requirements, most notably those related to safety and environmental protection. Such cases are initially investigated by the MMS and subsequently referred to the Department of Justice for trial in Federal Court. If a criminal penalty is assessed, it consists of a fine of up to 100,000 dollars or a prison term of up to ten years, or both.

IV. PERFORMANCE RECORD

A. Data

Tables 1 through 3 express with statistics the record of oil and gas operations on OCS leases. The source of the data in these tables is the computerized events file which the Department of the Interior has maintained since 1971. This file lists operational events including blowouts, spills, and accidents which have occurred on OCS leases and pipeline rights-of-way. The tables which have been compiled for this appendix present information only on blowouts and oil spills as follows:

- Table 1 OCS Oil Spills of 50 or More Barrels

All oil spills of 50 or more barrels which are recorded in the events file are listed. It must be recognized that information is incomplete on those spills which occurred before inception of the events file in 1971.

- Table 2 Recorded OCS Blowouts: 1954-1970

Blowouts recorded in the events file for the period covered from implementation of the OCS Lands Act in 1954 to the year 1970 are listed. Again, this list is incomplete, because no comprehensive file was established prior to 1971.

- Table 3 Recorded OCS Blowouts: 1971-1984

Blowouts recorded from inception of the events file are listed, as well as resulting spill amounts, number of new wells started each year, and total of oil and condensate produced each year.

A blowout is a sudden, often violent, release of hydrocarbons to the environment which is caused by loss of well control. It may cause personal injury or death and extensive property damage, and if crude oil or condensate is involved, an oil spill occurs. For the purposes of the events file and this appendix, an oil spill is considered any unauthorized release of crude oil, condensate or similar liquid hydrocarbon in the course of OCS operations. The source of an oil spill listed in the events file may be a well, pipeline or any vessel or structure directly involved in OCS exploration, development or production.

Blowouts and oil spills are identified in this examination of the OCS record, because they are negative, sometimes catastrophic, events which indicate failure to conduct safe and efficient operations as called for by the regulatory program. The release of hydrocarbons into the ocean may negatively affect the contacted environment and cause losses to other industries such as tourism and fishing. An oil spill which is not contained and reaches shore may cause severe damage to the coastal environment and exact tremendous cleanup expenses. Such losses and expenses, termed social costs, are discussed in depth in Appendix G.

Table 1 OCS OIL SPILLS OF 50 OR MORE BARRELS

Date	Operation	Region	Event	Pollution	Amount (barrels)
01/20/64	Drilling	GOM	Blowout	Crude Oil	100
10/03/64	Unknown	GOM	Blowout	Crude Oil	5,180
07/19/65	Drilling	GOM	Blowout	Crude Oil	1,688
01/28/69*	Drilling	PAC	Blowout	Crude Oil	10,000 (to 79,000)
03/16/69	Drilling	GOM	Blowout	Crude Oil	2,500
12/16/69	Production (Pipeline)	PAC	Spill	Crude Oil	900
02/10/70	Production	GOM	Spill	Crude Oil	30,000
05/28/70	Production	GOM	Spill	Crude Oil	100
12/01/70	Completion/ Workover	GOM	Blowout	Crude Oil	53,000
04/05/71	Drilling	GOM	Spill	Crude Oil	200
05/15/71	Production	GOM	Spill	Crude Oil	50
05/26/71	Production	GOM	Spill	Crude Oil	75
05/27/71	Production	GOM	Spill	Crude Oil	50
05/29/71	Production	GOM	Spill	Crude Oil	135
07/20/71	Storage Barge	GOM	Spill	Crude Oil	100
08/13/71	Production	GOM	Spill	Crude Oil	50
10/16/71	Production	GOM	Blowout	Crude Oil	450
11/14/71	Production (Pipeline)	GOM	Spill	Crude Oil	70
12/09/71	Production	GOM	Spill	Crude Oil	50
12/18/71	Production (Pipeline)	GOM	Spill	Crude Oil	80
06/13/72	Production (Pipeline)	GOM	Spill	Crude Oil	100
01/9/73	Production	GOM	Spill	Crude Oil	9,935
05/12/73	Production (Pipeline)	GOM	Spill	Crude Oil	5,000
06/20/73	Drilling	GOM	Spill	Diesel Fuel	239
12/08/73	Drilling	GOM	Spill	Diesel Fuel	95
04/17/74	Production (Pipeline)	GOM	Spill	Crude Oil	19,833
05/21/74	Production	GOM	Spill	Crude Oil	100
7/10/74	Production	GOM	Spill	Crude Oil	130
09/07/74	Production	GOM	Blowout	Crude Oil	75
09/09/74	Production	GOM	Spill	Crude Oil	2,213
10/04/74	Production	GOM	Spill	Crude Oil	50
11/27/74	Production	GOM	Spill	Crude Oil	120
12/22/74	Well Repair	GOM	Blowout	Crude Oil	200
3/18/75	Production	GOM	Spill	Diesel Fuel	166
09/21/75	Drilling	GOM	Spill	Diesel Fuel	100
02/29/76	Production (Pipeline)	GOM	Spill	Crude Oil	414
10/19/76	Production	GOM	Spill	Diesel Fuel	300
12/18/76	Production (Pipeline)	GOM	Spill	Crude Oil	4,000
03/29/77	Production (Pipeline)	GOM	Spill	Crude Oil	250
06/05/77	Production (Pipeline)	GOM	Spill	Crude Oil	50
10/18/77	Production (Pipeline)	GOM	Spill	Crude Oil	300
12/14/77	Drilling	GOM	Spill	Crude Oil	100
04/08/78	Production (Pipeline)	GOM	Spill	Crude Oil	135
05/11/78	Production	GOM	Spill	Crude Oil	104
7/10/78	Production	GOM	Spill	Crude Oil	900

* This spill occurred as a result of a blowout in Santa Barbara Channel. The events file reports that oil has continued to seep since the blowout, totaling about 27,000 barrels through 1984. Other sources have estimated the initial volume of this spill to be as high as 79,000 barrels.

12/11/78	Production	GOM	Spill	Crude Oil	100
01/30/79	Drilling	GOM	Spill	Diesel Fuel	321
01/31/79	Production	GOM	Spill	Diesel Fuel	165
04/14/79	Production	GOM	Spill	Crude Oil	60
09/21/79	Production (Pipeline)	GOM	Spill	Crude Oil	55
11/23/79	Drilling	GOM	Spill	Diesel Fuel	1,500
01/23/80	Production	GOM	Spill	Diesel Fuel	286
01/29/80	Production (Pipeline)	GOM	Spill	Condensate	100
05/16/80	Production	GOM	Spill	Diesel Fuel	150
06/11/80	Drilling	GOM	Spill	Diesel Fuel	80
10/15/80	Drilling	GOM	Spill	Diesel Fuel	83
11/13/80	Production	GOM	Spill	Crude Oil	1,456
12/02/80	Drilling	GOM	Spill	Diesel Fuel	116
02/15/81	Production	GOM	Spill	Crude Oil	58
04/06/81	Drilling	GOM	Spill	Mineral Oil	126
08/05/81	Production	GOM	Spill	Crude Oil	80
08/19/81	Drilling	GOM	Spill	Diesel Fuel	50
11/28/81	Service/ Workover	GOM	Blowout	Crude Oil	64
12/11/81	Boat Offloading (Pipeline)	GOM	Spill	Crude Oil	5,100
01/19/82	Drilling	GOM	Spill	Diesel Fuel	200
02/22/82	Unknown	GOM	Spill	Crude Oil	100
04/29/82	Drilling	GOM	Spill	Diesel Fuel	228
08/18/82	Drilling	GOM	Spill	Diesel Fuel	214
01/30/83	Drilling	GOM	Spill	Oil Base Mud	800
02/01/83	Port	GOM	Spill	Crude Oil	125

03/09/83	Drilling	GOM	Spill	Diesel Fuel	100
03/20/83	Drilling	GOM	Spill	Diesel Fuel	320
04/14/83	Production	GOM	Spill	Diesel Fuel	200
05/09/83	Drilling	GOM	Spill	Diesel Fuel	100
05/16/83	Drilling	GOM	Spill	Diesel Fuel	95
08/02/83	Production	GOM	Spill	Diesel Fuel	121
06/20/84	Production	GOM	Spill	Crude Oil	50
07/8/84	Drilling	GOM	Spill	Diesel Fuel	100

Table 2 RECORDED OCS BLOWOUTS: 1954 TO 1970

Year	Drilling Blowouts	Nondrilling Blowouts	Total
1954	0	0	0
1955	0	0	0
1956	1	0	1
1957	1	0	1
1958	1	0	1
1959	1	0	1
1960	1	1	2
1961	0	0	0
1962	1	0	1
1963	1	0	1
1964	5	2	7
1965	5	0	5
1966	2	0	2
1967	2	0	2
1968	6	1	7
1969	1	2	3
1970	1	1	2
Total	29	7	36

Table 3 RECORDED OCS BLOWOUTS: 1971-1984

Year	No. of New Wells Started	Production: Oil and Condensate in Barrels (Millions)	Drilling Blowouts: Exploration No.	Drilling Blowouts: Exploration Barrels Spilled	Drilling Blowouts: Development No.	Drilling Blowouts: Development Barrels Spilled	Nondrilling Blowouts: Production No.	Nondrilling Blowouts: Production Barrels Spilled	Nondrilling Blowouts: Workover No.	Nondrilling Blowouts: Workover Barrels Spilled	Nondrilling Blowouts: Completion No.	Nondrilling Blowouts: Completion Barrels Spilled	Total No. of OCS Blowouts	Total No. of OCS Blowouts: Barrels Spilled
1971	841	418.5	2	0	0	0	2	450	1	0	0	0	5	45[illegible]
1972	847	411.9	2	0	1	0	0	0	0	0	0	0	3	[illegible]
1973	820	394.7	2	0	1	0	0	0	0	0	0	0	3	[illegible]
1974	816	360.6	0	0	1	0	2	75	1	200	0	0	4	27[illegible]
1975	882	330.2	4	0	0	0	0	0	1	0	1	0	6	[illegible]
1976	1,041	316.9	1	0	4	0	1	0	0	0	0	0	6	[illegible]
1977	1,158	303.9	2	0	2	0	0	0	3	0	2	0	9	[illegible]
1978	1,148	292.3	4	0	5	0	0	0	2	0	1	0	12	[illegible]
1979	1,109	285.6	3	0	2	0	0	0	0	0	0	0	5	[illegible]
1980	1,079	277.4	3	0	1	0	1	1	2	0	1	0	8	[illegible]
1981	1,106	286.6	2	0	1	0	0	0	2	64	5	0	10	6[illegible]
1982	1,155	321.1	0	0	4	0	0	0	3	0	1	0	8	[illegible]
1983	1,066	340.7	3	0	4	0	0	0	1	0	1	0	9	[illegible]
1984	1,144	380.0	3	0	1	0	0	0	0	0	0	0	4	[illegible]
Total	14,212	4,720.4	31	0	27	0	6	526	16	264	12	0	92	79[illegible]

B. Conclusion

Tables 1 through 3 and information available from other sources indicate that the overall record of OCS oil and gas operations has been excellent. Table 1 shows that since inception of the events file, the number of 50 barrel or more oil spills per year has averaged 4.9, and only four spills of over 1000 barrels have occurred during the past ten years. Table 3 indicates that the number of blowouts which occurred between 1971 and 1984 represents sixty-five thousandths of one percent of the total of all new wells started during this time. Only 5 blowouts during the same period resulted in oil spills, and the 790 barrels of oil spilled as a result of these blowouts constitutes an infinitesimal percentage of total produced oil and condensate. Moreover, the National Academy of Sciences' recent publication, Oil in the Sea, reports that during the period 1971-1978, the average spillage rate in the Gulf of Mexico was twenty-two thousandths of one percent of the total crude oil produced. The Gulf of Mexico OCS produced 2,691,200,000 barrels of oil during this period.

Since the Santa Barbara Channel blowout in 1969, which resulted in a large oil spill that is the only United States OCS spill ever to contact shore in significant amounts, operating regulations have been strengthened and great technological advances have been made. Overall procedures governing operations, requirements pertaining to blowout preventers and production safety systems, the actual capabilities of such pollution prevention equipment, and the MMS compliance inspection program have promoted extremely safe and environmentally sound operations.

Appendix R

Methodology Used To Value The Base Schedule Option

Description of The Methodology Used To Estimate Value for the Base Schedule

The same data developed for net social value based on the estimation of net economic value (Appendix F) and social costs (Appendix G) for each planning areas were used to value the sales in the base schedule option. The economic assumptions used are consistent with the net economic analysis--i.e., a base case oil price of $24 per barrel (July 1984 starting price), a 1 percent annual real oil price growth, and an 8 percent discount rate. However, unlike the net economic value calculation which estimated value for all leasable resources if leased at the beginning of 1987, the schedule valuation exercise required estimation of the amount of resources which would be leased at the time of each lease sale.

The amount of resources estimated to be leased in each sale for all planning areas was projected based on past leasing experience, and knowledge of the resource potential, development costs, and industry interest in the various planning areas. The sale size assumed in these projections reflects the currently used presale process of "focusing on promising acreage" (the size decision option selected in the Draft Proposed Program). It should be noted that the ultimate benefits and costs associated with this 5-year program will differ from the results of this analysis with any changes in the sale timing (e.g., postponement of sales) or with specific lease sale decisions regarding subarea deferrals and sale size in the Proposed Program.

The amount of resources projected to be leased in a sale within each planning area are based on those resources which are economically "developable" i.e., resources which are economic to develop, given that they have been discovered. In many cases, these projections exceed the amount of resources classified as "leasable" for purposes of calculating net economic value in Appendix F. The projections of resources expected to be leased and the estimates of leasable resources were generated for different purposes and therefore have different meaning. Estimates of "leasable" resources provide a basis for computing the measure of a planning area's net economic value for a given set of economic assumptions at the start of the next 5-year program. This measure allows for a ranking of the prospective nature of planning areas at that time.

On the other hand, the value of a particular schedule in which resources are leased over the time period beginning in January 1987 depends upon a broader set of factors than simply "leasable" resources to generate sale-specific resource acquisition. These additional factors which must be considered in the valuation analysis for estimates of resources which are expected to be leased include:

- the entire range of leasable resources under different economic conditions;
- the aggregate cost of transportation networks;
- the estimates of the growth of economically recoverable and leasable resources through time, assuming increases in real oil prices;
- consideration of alternative estimates of resource potential that may be calculated by bidders and reflected in the range of industry interest for particular areas;
- consideration that some of the tracts leased and explored by firms with optimistic expectations might turn out to contain deposits that are worth developing even though they would not have been worth the expenses of leasing and exploration had the firms had accurate knowledge of the size of the deposit; and
- the recognition that early exploration in frontier areas can reveal the presence of oil and gas, thereby increasing the probability of discovery on the prospects remaining to be explored. Such increases in the probability of success can make prospects that are developable but not leasable into leasable prospects.

Thus, while "leasable" resources influence the sale-specific resource levels, the aggregate amount of resources projected to be leased in a given planning area over a 5-year period is not constrained by the "leasable" resources estimated for the net economic value calculations.

The specific estimates of resource acquisition by sale, and the estimates of economically recoverable (developable) resources remaining at the end of the 5-Year Program, are presented in Table 1.

The net economic value estimates for each planning area derived in Appendix F, were used to estimate a value at the time of sale for the resources expected to be leased. Resources were assumed to be sold in order from the highest valued prospects to the lowest valued (see Appendix F, Table 7). Where projections of resources expected to be leased exceeded the resources which were classified as leasable for the January 1987 net economic value calculations, value was inferred using an approach developed in Appendix F. This approach calculates the economic value for those resources assuming that they have a zero private value; i.e., they are marginally worth leasing.

Because the net economic value estimates reflect value as of the beginning of the 5-Year Program, the estimates had to be adjusted to reflect the increased value for resources sold in later years. This adjustment was made by applying a 1 percent annual real rate of price growth to the revenue streams associated with each net economic value category, while assuming that the cost streams remain constant. The resulting rate of growth in net economic value (revenues minus cost of production and transport) could then be used to estimate the adjusted net economic values of sales for the years in which they are scheduled. From these values, social costs were deducted to arrive at net social value at the time of sale for those resources expected to be leased in each sale. These sale values were then discounted back to 1987 at an 8 percent discount rate.

In estimating the value for the base schedule, it is important to take into account not only the value of the scheduled sales, but also the value of remaining unleased resources. To estimate value of the remaining resources, unleased as of the end of the new 5-year program, an assumption had to be made regarding the pace of leasing in each planning area after 1991. For purposes

Table 1

Risked Economically Developable Resources
Expected to be Leased Under the Base Case Schedule
(Millions of barrels of oil equivalent)

Planning Area	1987	1988	1989	1990	1991	Unleased Remaining Developable Resources
North Atlantic	-	38	-	-	28	284
Mid-Atlantic	-	-	100	-	-	700
South Atlantic	-	-	75	-	-	815
Western Gulf of Mexico	466	400	266	200	200	3,098
Central Gulf of Mexico	643	551	459	459	367	2,701
Eastern Gulf of Mexico	-	64	-	-	56	460
Southern California	355	-	-	236	-	1,009
Central California	-	-	168	-	-	292
Northern California	-	149	-	-	99	202
Oregon-Washington	-	-	-	-	49	101
Beaufort Sea	224	-	-	215	-	21
Chukchi Sea	123	-	-	107	-	301
Norton Basin	-	-	30	-	-	10
Navarin Basin	489	-	-	142	-	459
St. George Basin	-	-	79	-	-	301
N. Aleutian Basin	-	-	79	-	-	11
Shumagin	8	-	-	-	-	2
Gulf of Alaska	-	-	-	-	-	150
Cook Inlet	-	-	-	-	-	10
Kodiak	-	-	-	-	-	30
Hope	-	-	-	-	-	10
Florida Straits	-	-	-	-	-	20

of this valuation analysis, the pace of leasing established under the base schedule option was continued until all developable resources in each planning area were exhausted. The amount of resources expected to be leased each year after 1991 was assumed to be approximately that rate projected for the last sale in each planning area. This is an improvement over the methodology used in the 1982 analysis; however, it should be noted that there is great uncertainty surrounding how or if resources would be leased in each planning area for future 5-year programs.

The results of this valuation process are presented in Table 2 for both the sales scheduled in the 5-Year Program and the resources remaining unleased as of 1992. Note that the values estimated for the 5-year program sales are shown both at the time of sale and discounted to January 1987. The value of the remaining resources is shown for 1992, where the sales scheduled beyond 1992 have been discounted to the end of the 5-year program. This 1992 value is then discounted to 1987.

Table 3 is a summary of the results where net social value for the base schedule in 1987 (beginning of the 5-year program) is estimated by adding the discounted net social value for the sales scheduled to be held during the 5-Year Program to the discounted net social value of the remaining unleased resources.

Table 3

Discounted Net Social Value of the Base Schedule and Remaining Unleased Resources /1
($Millions, Except Totals)

Planning Area	Discounted Net Social Value /2: Base Schedule	Discounted Net Social Value /2: Remaining Unleased Resource
North Atlantic	147	147
Mid-Atlantic	359	503
South Atlantic	290	855
Western Gulf of Mexico	8,489	7,513
Central Gulf of Mexico	13,859	7,544
Eastern Gulf of Mexico	499	525
Southern California	3,884	1,811
Central California	739	684
Northern California	1,267	342
Oregon-Washington	247	159
Beaufort Sea	550	19
Chukchi Sea	220	236
Norton Basin	42	12
Navarin Basin	1,058	357
St. George Basin	109	289
N. Aleutian Basin	26	4
Shumagin	10	2
Gulf of Alaska	0	45
Cook Inlet	0	10
Kodiak	0	25
Hope	0	6
Florida Straits	0	33
Totals	$32 billion	$21 billion

/1 The uncertainty associated with estimating resources and net social value, as described throughout the text of the SID and this appendix, is compounded in the formulation of a leasing schedule. Furthermore, the relative uncertainty in the numbers in this table is, in part, based on the adequacy of data for each planning area. (See Table 12-1 in this SID and Appendix E.)

/2 Net social value is discounted to January 1987--the projected start of the 5-Year Program.

/3 The values of remaining unleased resources do not include estimates of resources in currently uneconomic prospects which become economical as hydrocarbon prices increase in the future. See Appendix F, section V.C.

Table 2

Value of Base Schedule and Remaining Developable Resources
($Millions, Except Totals)

Planning Area	Net Social Value at the Time of sale for resources expected to be leased under the Base Schedule: 1987	1988	1989	1990	1991	Discounted (to 1/87) Net Social Value of Schedule	Net Social Value of Remaining Unleased Resources: Discounted to 1/92	Discounted to 1/87
North Atlantic	-	86	-	-	99	147	217	147
Mid-Atlantic	-	-	435	-	-	359	739	503
South Atlantic	-	-	352	-	-	290	1,257	855
Western Gulf of Mexico	3,416	2,488	1,526	1,167	1,187	8,489	11,039	7,513
Central Gulf of Mexico	4,610	3,657	3,091	2,726	2,181	13,859	11,085	7,544
Eastern Gulf of Mexico	-	342	-	-	276	499	772	525
Southern California	2,676	-	-	1,717	-	3,884	2,622	1,811
Central California	-	-	897	-	-	739	1,006	684
Northern California	-	1,081	-	-	431	1,267	502	342
Oregon-Washington	-	-	-	-	350	247	233	159
Beaufort Sea	337	-	-	296	-	550	28	19
Chukchi Sea	131	-	-	124	-	220	347	236
Norton Basin	-	-	51	-	-	42	18	12
Navarin Basin	905	-	-	246	-	1,058	525	357
St. George Basin	-	-	132	-	-	109	425	289
North Aleutian Basin	-	-	32	-	-	26	6	4
Shumagin	11	-	-	-	-	10	3	2
Gulf of Alaska	-	-	-	-	-	0	67	45
Cook Inlet	-	-	-	-	-	0	15	10
Kodiak	-	-	-	-	-	0	37	25
Hope Basin	-	-	-	-	-	0	9	6
Florida Straits	-	-	-	-	-	0	49	33
Totals (in $Billions)						32		21

APPENDIX S

LIMITATIONS OF THE TECHNICAL SECTION 18 ANALYSES

Limitations of the Technical Section 18 Analyses

There are inherent and unavoidable limits on the precision of the analyses which have been performed under section 18. The limits of the analyses required under section 18 are explained in Part II.B and Appendices E, F, G, and I. A combined summary account of those explanations appears in this appendix.

The court addressed this issue in California v. Watt (II) in the following terms:

> It is important to understand what is being evaluated . . . . [T]he factual basis and the methodology used by the Secretary in various aspects of the cost benefit analysis . . . fall within what the court in Watt I described as the "frontiers of scientific knowledge." The facts used by the Secretary in performing the analysis are largely predictive in nature, and the methodology utilized was necessarily novel because this type of analysis has not been performed extensively in the past. Thus, as the court in Watt I observed, great deference is afforded to the Secretary in these areas. "Where existing methodology or research in a new area of regulation is deficient, the agency necessarily enjoys broad discretion to attempt to formulate a solution to the best of its ability on the basis of available information." Therefore, although we are obligated to review the factual findings of the Secretary in order to determine that they are supported by substantial evidence in the record, we realize that these findings must be somewhat speculative. Further, we are required to sustain the methodology and assumptions made by the Secretary if they are reasonable. /1

This SID incorporates the following approaches, which reflect a recognition of those limitations:

a. Evaluating the Adequacy of Data

In order to provide a way of evaluating the results of the various technical analyses, an indication will be given of the adequacy of the data on which they are based. For example, the grid coverage and quality of the geologic and geophysical data which is the basis of much of the analysis in this SID ranges from "Excellent" for some areas to "Very Poor" in others. Table 12 in the SID and Appendix E contain an evaluation of such data for each planning area.

b. Analyzing the Sensitivity of the Analyses to Key Assumptions

Where reasonable changes in technical assumptions could produce significant changes in the results of analyses, sensitivity analyses are provided. These analyses show the effects of different assumptions on the results of the technical analyses. For example, the analysis of net economic value includes a sensitivity test which shows the variation of leasable resource estimates given starting oil prices ranging from $19 to $29 per barrel (see Appendix F).

/1 California v. Watt (II) at 600

c. Providing Ranges and Variations of Estimates

Given the uncertainties involved in the data, ranges and variations of estimates are an informative supplement to measures of central tendency and point estimates. The SID provides a range for conditional estimates of unleased undiscovered OCS oil and gas resources as of March 1985 (SID Table 1). Variations of estimates corresponding to assumed starting oil prices of $19 to $29 per barrel are also provided in the SID for net economic value, social costs, and net social value.

d. Overestimation of Costs

A cautious approach in formulating the technical analyses is taken, erring on the side of understating economic benefits to the Nation and overstating social costs to the Nation, while still aiming at a reasonable estimation of both (see Appendix G).

e. Providing Perspective on the Estimates of Costs and Benefits

In making comparisons between planning areas based on the cost-benefit analysis, the relative values calculated for OCS areas are accorded much more importance than the absolute values. Further, OCS areas with estimates within the same general range of value are not considered to differ for purposes of program formulation. Thus, for example, planning areas are formed into groups and subgroups whose members are treated alike, all things being equal, for the scheduling of sales (see Part II.D and Part III.A.2).

f. Supplementing Government Analyses with Public Comments

Pursuant to section 18, consultation with and comments by parties outside the Federal Government are used to provide additional information. The consideration of outside comments is an important element in the decisionmaking process. Responses to the March 1985 requests for comments are summarized in Appendices B and D.

g. Highlighting the Role of Judgment in Interpreting the Technical Analyses and Formulating the Leasing Program

The fact that the technical analyses performed pursuant to section 18 have inherent and unavoidable limits has important implications both for the decisionmaking process leading to the new 5-year program and for the structure of that program. In terms of the decisionmaking process, the limits of the quantitative analyses make clear the prudence of the court's opinion in California v. Watt (II). The court found that the Secretary's decision on the leasing program is to be based on a consideration of quantitative analyses rather than determined by the results of those analyses in a mechanistic way. Thus, there remains for the Secretary substantial scope for the exercise of judgment based on non-quantifiable considerations and limitations on the quantitative analyses. These considerations and limitations are highlighted in the SID and its appendices.

Recognition of the limitations of the technical analyses and projections of future conditions also casts light on the kind of leasing program appropriate to meet the objectives specified by Congress and the National Energy Policy Plan. The many uncertainties which affect planning for OCS leasing make clear the value of flexibility in the OCS leasing program. Indeed, the issue in formulating a new program is not whether to provide for flexibility, but how. For example, the 5-year schedule responds easily to declines in prices and other factors, which tend in the direction of less bidding interest by industry or the deferral or cancellation of sales. The 5-year program is characteristically rigid, however, with respect to responding to circumstances which call for the addition of sales. This issue will be discussed further in Part III of this SID. Comments on this issue were requested in the March 1985 Federal Register Notice and are summarized in Appendix B.

Summary Discussion of the Limits of the Technical Analyses

--Geological and Geophysical Data

Geological and geophysical data are typically the beginning point for assessing the consequences of OCS oil and gas leasing. A great amount of such data has been accumulated and interpreted by the MMS and other parties (see Appendix E). Nonetheless, the following limiting factors about that data base need to be considered.

The collection and analysis of data for attempting to predict the presence of oil and gas are costly. Although some data are collected by the MMS, most are collected by firms exploring for oil and gas and are made available to MMS by those firms. Thus, the extent and location of the geological and geophysical data gathered have been determined primarily by private firms' assessment of the potential payoffs from acquiring leases and exploring for oil and gas. Since this process is governed by economic factors such as oil prices as well as the opportunity to acquire leases and find oil and gas, knowledge of estimated undiscovered resources is inherently incomplete and is limited in areas and prospects that have not been made available for leasing or have not appeared economically attractive to one or more companies. A paucity of data for an area greatly increases the uncertainty surrounding its geologic characteristics and thus its resource potential. More emphasis must be placed on indirect means of assessment, such as comparison to geologically similar basins where there has been significant exploration. In these cases, the estimates are only as good as the selection of analogs; that is, the estimates are highly speculative. In this connection, see Appendix E.

In addition, the estimation of undiscovered resources typically assumes a set of prices and costs consistent with current expectations. Extrapolation to include resources that are recoverable only at significantly higher price levels would require a basic reevaluation of existing geologic data as well as the accumulation of additional data not now available because of its high cost

and limited private value. Estimates of resources that are economic under current expectations thus potentially understate the resources that are likely to be found and discovered in the future. Even for areas and prospects for which there are substantial seismic data, the resource potential can only be measured in probabilistic terms until exploratory wells have been drilled. Thus, one hundred prospects may each have a one-in-ten chance of containing 100 million barrels of oil. Before drilling, each must be regarded as having the same resource potential. Drilling could reveal, however, that 90 of the 100 prospects had no oil while 10 have 100 million barrels each. The same holds true for large areas that have not had exploratory drilling. Thus, a leasing program must be based on probabilistic estimates of resources for various areas despite the fact that some areas will turn out to have no oil and gas while others have a great deal.

There are also technological limits to the available data. Interpretation of seismic data is imperfect and may leave many deposits unidentified for many years. Even the targeting of prospects for drilling involves far more failures than successes.

The greatest element of cost--drilling wells--is also the most crucial to the evaluation of the data because the actual presence of hydrocarbons in a geologic structure can only be established by drilling. Drilling wells--often many wells, most of which are dry holes--is necessary before deposits of oil and gas can be discovered and delineated--if they are present in an area at all. Over 100 dry holes at a cost of up to 10 million dollars each were drilled before the recent hydrocarbon discoveries in the Canadian North Atlantic. The history of exploration in Prudhoe Bay and in the North Sea is comparable. Over 100 exploratory wells have been drilled in the OCS off the Atlantic Coast States, in the Eastern Gulf of Mexico, in the Bering Sea, in the Gulf of Alaska, and in Cook Inlet without a commercial discovery.

Section 102(9) of the OCS Lands Act clearly recognizes the incomplete nature of geologic knowledge in mandating that ". . . the extent of oil and natural gas resources of the Outer Continental Shelf [be] assessed at the earliest practicable time." Since the OCS Lands Act for the most part ties the right to drill to the acquisition of a lease, the OCS leasing program has to be seen, at least in part, as a program that facilitates the acquisition of better geological data by potential producers for use by them and by the Government. The leasing program thus has a major influence on progress in resource assessment.

--Economic Projections

The projection of the economic benefits of OCS leasing also reflects the unavoidable limits to precision in OCS program planning (see Part II.B and Appendix F). The chief limits here are the uncertainties attendant on the prediction of future oil prices or rates of price increases or decreases, and the selection of a discount rate.

The quadrupling of oil prices (in constant dollars) between 1973 and 1981--and their subsequent decline--makes clear the difficulty of predicting prices. This difficulty is compounded by the long time period which the prediction must cover. The period from leasing to the end of production, if there is any production, is generally projected to be on the order of 20 to 30 years.

Geopolitical factors cause further limits on the precision of price predictions used in planning for OCS leasing. A major, long-term change in the political order of a few or even only one nation in the Middle East could have enormous effects on world oil supplies and prices. The 5-year OCS leasing program must take into account this possibility as a matter of prudence given the purposes of the OCS Lands Act Amendments. This consideration is discussed further in Part II.A.

The comparison of economic benefits among planning areas is facilitated by estimation of the net economic value of the resource potential in each area. This requires the calculation of the net present value of the stream of estimated production revenues minus the stream of exploration, production, and transportation costs which are projected to occur over time. This gives the value of Federal receipts and lease profits discounted to January 1987 which is equivalent to the production revenues (net of costs) over the economic life of the venture.

The calculation of net present values requires the selection of a discount rate. The discount rate is a measure of the time value of money representing how much more a dollar of benefits or costs is worth to us in the present than in the future. The selection of a discount rate thus inevitably calls for a judgment about how much the country will value benefits which will accrue in the future as opposed to the present. There is controversy among economists about the basis for selection of a discount rate. There is also uncertainty about the future economic conditions which it is intended to reflect. Thus there is uncertainty about the proper value of this important factor.

Because of these inherent uncertainties in the data, projections, and methods used to produce quantitative estimates of benefits and costs, efforts have been made to analyze qualitatively the effects of different aspects of the OCS leasing program under different future conditions. Particular attention has been paid to the effects of leasing on the timing of investments in OCS exploration and development and on the benefits to the U.S. economy under different future conditions in the world oil market.

--Estimates of Social Costs

Like the analysis of economic benefits, the analysis of social costs also bears the burden of predicting prices and selection of a discount rate (see Part II.B and Appendix G). The analysis of social costs has assumed the additional burden of quantifying certain potential costs of oil and gas development not valued by the market. This effort helps to provide an estimate of the social cost of oil and gas development in dollars so that the overall net social value (net economic benefits minus social costs) can be computed for oil and gas development in each planning area. This cost-benefit approach was part of the guidelines issued by the court in California v. Watt (I) and its execution was validated by the court in California v. Watt (II).

Estimates of social costs which are not valued in the market cannot be considered entirely comparable to estimates of net economic value. The reason for this is that the estimation of social costs expressed in dollar terms are not generally

accepted measures, unlike the market values used in the net economic value analysis. In addition, beyond the comparison of costs and benefits expressed in dollar terms, qualitative as well as quantitative information needs to be considered.

--Analysis of Relative Marine Productivity and Environmental Sensitivity

The analysis of the relative marine productivity and environmental sensitivity of OCS planning areas called for by section 18 has limits comparable to those of the analysis of social costs (see Part II.B.3 and Appendix I). The SID analysis of social costs quantifies some of the externalities not included in the calculation of net economic value. The SID analysis of relative marine productivity and environmental sensitivity, at least in part, develops numerical coefficients of the level of sensitivity of individual habitats and biota which are then used to generate combined productivity and sensitivity measures which are used to compare OCS planning areas. The calculation of productivity and sensitivity measures is subject to limitations such as the abstract nature of the measures as contrasted to the factors which they represent and the unavoidable need for professional judgment not reducible to technique in the determination of the sensitivity coefficients. These limitations affect the marine productivity and environmental sensitivity analysis both insofar as that analysis is to be considered in itself and insofar as it serves as an input to the analysis of social costs.

In addition, the availability of marine productivity and sensitivity data is limited by the data base available as the result of past investigations and the costliness of the acquisition of new information. The efforts of the MMS to acquire more data through its environmental studies program are described in Appendix H.

Attachment 5

PROPOSED PROGRAM

5-Year Outer Continental Shelf Oil and Gas Leasing Program for January 1987 - December 1991

Subarea Deferrals Suggested by Commenters

OCTOBER 1985

PROPOSED PROGRAM

5-YEAR OUTER CONTINENTAL SHELF OIL AND GAS LEASING PROGRAM FOR JANUARY 1987 - DECEMBER 1991

UNITED STATES DEPARTMENT OF THE INTERIOR

MINERALS MANAGEMENT SERVICE

SUBAREA DEFERRALS SUGGESTED BY COMMENTERS
OCTOBER 1986

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North Atlantic Planning Area

Georges Bank Region (200 meter contour)

a. Geographic Description

This subarea deferral candidate encompasses 1,621 blocks and covers an area of 9,228,651 acres (3,734,784 hectares). The Georges Bank region within the 200 meter contour encompasses the Georges Bank Basin proper, a structural depression in the crystalline basement rock. This area is located approximately 47 to 165 miles offshore southeastern New England, and in water depths of about 36 to 200 meters. The Georges Bank Basin is 280 km (174 miles) long and 150 km (93 miles) wide.

b. Sales (and date held) for which the Subarea was Studied and Disposition in Each Sale

Georges Bank region (200 meter contour):
- o Not studied as a alternative at the EIS stage
- o Deferred all blocks less than 400 meters except high interest blocks in Sale 82 (Part I cancelled 9/84)

c. Oil and Gas Resource Potential

This area contains the thickest accumulation of sedimentary rocks found in the planning area that, in places, may exceed 35,000 feet. Large Triassic rift-basins (some of which may contain over 15,000 feet of sediment), numerous anticlinal structural traps, and some patch reefs of Mesozoic age occur within the subarea. A few large structures identified in the eastern part of the area are found to straddle the U.S.-Canadian boundary line extending into Canadian waters.

In the southern part of the subarea, data coverage is sufficient to define specific prospects and, locally, specific plays within prospects. Data coverage in the northern part is sufficient to identify major trends associated with Triassic rift-basin and associated structures and stratigraphic traps.

The Jurassic/Cretaceous paleo-shelf edge complex (considered a potential exploration trend) contains both structural and stratigraphic traps and occurs just seaward of the southern boundary of the subarea.

With regard to oil and gas potential, recent findings indicate that the southern part of the subarea is prospective, but, the northern part appears to be not as prospective. Some of the rift-basin structures have been of interest to the industry and, although very risky, they may contain significant resources. The greater percentage of resources lies seaward of the 200 meter isobath.

d. Description of the Environment

Georges Bank is an area of high biological productivity resulting from complete vertical mixing of water throughout the year on the shallow crest of the bank. There is no thermocline to restrict the upward flow of deep-water nutrients to the surface. Zooplankton abundance and fish stocks have higher levels of standing stock at the shelf break zone than the open ocean or shelf areas. Several important commercial groundfish species aggregate south and offshore of Georges Bank in deep water (>100 meters) during late winter and spring spawning seasons. In the Great South Channel the endangered right whales have been seen feeding on plankton and the endangered humpback whales have been seen feeding on schools of fish. The bulk of Georges Bank infauna consists of Crustacea, Echinodermata, Mollusca, and Annelida. High densities of seabirds occur in this area in the summer, fall, and winter.

e. Potential Impacts Avoided by Deferral of this Subarea

Water quality impacts would be reduced from moderate to low. The likelihood of weathered oil and toxic products, resulting from a large accidental oil spill, being entrained and circulated within the Georges Bank gyre would be reduced. Impacts from routine discharges (muds and cuttings, formation water, sanitary/domestic wastes) would remain localized and low.

Regionally, deferral of this area would negligibly reduce possible impacts. Deferral of this area would eliminate exclusionary impacts on commercial fisheries because of oil rigs. Local oiling of seabirds, because of a platform spill, could be avoided and possible impacts to whales decreased. The possibility of an accidental oil spill being entrained in the Georges Bank gyre and causing potential major local impacts to commercial fisheries would essentially be eliminated.

f. Deferral Recommended by

Greenpeace

North Atlantic Planning Area

Georges Bank Region (400 meter contour and the submarine canyons)

a. Geographic Description

This candidate encompasses 1,708 blocks and covers an area of 9,723,958 (3,935,232 hectares). This area lies east and southeast of Georges Bank proper. It is a relatively steep area characterized by numerous deep submarine canyons and hummocky topography with gullies and terraces cutting across the surface. This area is considered the upper continental slope and parallels the Georges Bank shelf, beginning roughly at the shelf break (approximately 200 meter water depth). Several of the submarine canyons impinge on the outer shelf area. This area ranges from approximately 80 miles to 175 miles offshore southeastern New England.

b. Sales (and date held) for which the Subarea was Studied and Disposition in Each Sale

Submarine Canyons:
- o Studied in the following EISs:
  - Sale 52 (sale cancelled 8/83)
  - Sale 82 (Part I cancelled 9/84)--all canyon area blocks were deferred before the FNOS

c. Oil and Gas Resource Potential

This area contains the thickest accumulation of sedimentary rocks in the planning area which, in places, may exceed 35,000 feet. Large Triassic rift-basins (some of which may contain over 15,000 feet of sediment), numerous anticlinal structural traps, and some patch reefs of Mesozoic age occur within the subarea. A few large structures identified in the eastern part of the area are found to straddle the U.S.-Canadian boundary line extending into Canadian waters. Additionally, part of this modern upper continental slope acreage is underlain by parts of the Jurassic/Cretaceous paleo-shelf edge carbonate buildup. Prospectiveness is thought to increase toward the carbonate buildup.

d. Description of the Environment

The Georges Bank continental slope is a steep, narrow area paralleling the shelf and extending from the shelf break to depths of about 2,000 meters. The slope surface exhibits a varied topography with surface deposits consisting of fine-grained silt and clay. Submarine canyons incise the slope shoreward. Canyon walls tend to exhibit numerous exposures of outcrops as well as steep talus slopes. Although the silt/clay biotype has a low productivity associated with it, the area is known to support significant populations of groundfish and lobsters with highest concentrations in the canyon heads. Megafaunal abundances are generally higher in the canyon than on the slope at similar depths. Dense localized populations of corals, sponges, and shrimp contribute to the higher megafaunal numbers.

e. Potential Impacts Avoided by Deferral of this Subarea

Water quality impacts, as may result from a large accidental oil spill, would be reduced from moderate to low.

Georges Bank and the canyon areas support a large fixed gear and trawling industry. The current flow and transportation of sediments within the canyon axis varies for each canyon. Deferral of this subarea would eliminate potential moderate impacts from mechanical activities, possible drilling fluid dispersment within canyons, and local spills near heavily fished areas. On a regional basis, deferral of this area would reduce potential impacts from low to negligible.

f. Deferral Recommended by

State of Massachusetts, Massachusetts Audubon Society, Natural Resources Defense Council

North Atlantic Planning Area

Gulf of Maine (North of 42° 30')

a. Geographic Description

This subarea deferral candidate encompasses 1,846 blocks and covers an area of 10,509,617 acres (4,253,184 hectares). The Gulf of Maine is an area of extremely thin sediments, lying east of Massachusetts, New Hampshire, and Maine. It extends eastward from the nearshore region to the 200m isobath along the inner margin of Georges Bank and includes the Northeast Channel and the region southwest of the Scotian Shelf.

b. Sales (and date held) for which the Subarea was Studied and Disposition in Each Sale

Gulf of Maine
- o Not studied as an alternative at the EIS stage
- o Area never offered

c. Oil and Gas Resource Potential

This area is underlain by numerous large Triassic rift-basins. Present information on the occurrence and distribution of these grabens is based solely on literature studies. No data exist from this subarea to properly identify and evaluate structural and stratigraphic traps. Thus, oil and gas potential is unknown.

d. Description of the Environment

The State territorial waters of Maine, New Hampshire and northern Massachusetts form the western boundary of this subarea deferral candidate. This is a high-energy coastline, composed predominantly of rocky headlands. The exposed rocky shore supports a dense and diverse assemblage of invertebrates which are an important food source for a variety of seabirds. A jet-like current in the Georges Bank area forms a quasi-permanent boundary between the Gulf and the Bank. High concentrations of commercial macrobenthic organisms and groundfish are found on the fringes of the area. Fishes of the Gulf of Maine demonstrate limited movement into adjacent waters. Most stocks are fully or nearly fully exploited. The endangered humpback and right whales are known to migrate into (spring) and exit (fall) the Gulf of Maine and more northern waters. The endangered leatherback turtle has been observed feeding in the Gulf in June and in more northern waters throughout the summer. The coastline from northern Massachusetts, New Hampshire, and Maine provides extensive recreational opportunity and supports a healthy tourism industry.

e. Potential Impacts Avoided by Deferral of this Subarea

This subarea deferral would eliminate any potential for onshore visual impacts to coastal Maine, New Hampshire, and northern Massachusetts resulting from offshore drilling facilities. The risk of impacts to coastal recreation areas from platform spills would also be substantially reduced.

The extent of this deferral would also reduce the likelihood of land-use impacts from onshore facilities in Maine, New Hampshire, or Massachusetts. Such facilities would likely be located elsewhere in the region.

Overall, the water quality impact, resulting from a large, accidental oil spill would be reduced from moderate to low. However, the potential of high impact to limited coastline, and especially embayment areas, would be substantially reduced to a low level. The potential for rapid transport of large amounts of freshly-spilled oil to the coast or towards the Bay of Fundy by the Gulf of Maine circulation would be virtually eliminated.

Deferral of this subarea would further decrease the expected low impact on sea birds. A deferral would reduce local impacts from rig placements and oil spills on benthos, fish, and whales.

f. Deferral Recommended by

State of Maine, State of Massachusetts

North Atlantic Planning Area

North of 40° 15' North Latitude

a. Geographic Description

This candidate encompasses 3,837 blocks and covers an area of 21,844,747 acres (8,840,448 hectares). This area encompasses the Georges Bank slope out to 400 meter water depths, Georges Bank proper out to 200 meters, and the Gulf of Maine, all previously described.

b. Sales (and date held) for which the Subarea was Studied and Disposition in Each Sale

North of 40°15':
- o Not studied as an alternative at the EIS stage
- o Offered and 63 leases issued in Sale 42 (December 18, 1979)

c. Oil and Gas Resource Potential

The subarea is mostly confined to the continental shelf except for the southeast corner where slope and deep-water upper rise acreage is included. The western part of the area contains a number of large Triassic rift-basins and a few structural traps. In the southern part of the subarea, data coverage is sufficient to define specific plays within prospects. Data coverage in the northern part is sufficient to identify major trends associated with Triassic rift-basins, associated structures, and stratigraphic traps.

A large segment of the Mesozoic paleo-shelf edge complex (a possible exploration trend consisting of structural and stratigraphic traps) occurs entirely within the subarea (southeastern part). A few isolated structures, also present in the southeastern part, may be related to salt diapirism.

Most of the prospective acreage of this subarea is located in the southeastern part. Elsewhere, except for the Gulf of Maine where the oil and gas potential is unknown, the acreage is not as prospective.

d. Description of the Environment

This subarea is a composite of previously described areas. In essence, all of the North Atlantic fishing grounds, suspected feeding areas, and migratory routes for the endangered right whales, humpback whales, and leatherback turtles would be deferred.

e. Potential Impacts Avoided by Deferral of this Subarea

This subarea deferral would eliminate any potential for onshore visual impacts to coastal Maine, New Hampshire, and Massachusetts resulting from offshore drilling facilities. The risk of impacts to coastal recreation areas from platform spills would also be substantially reduced.

This deferral would also reduce the likelihood of land use impacts from onshore facilities in Maine, New Hampshire or Massachusetts. Such facilities would likely be located elsewhere in the region.

The overall water quality impact related to a large oil spill would be reduced from moderate to low. Potentially high local impacts to coastlines and embayments would also be reduced to a low level.

All local impacts to the fauna would be entirely avoided and regional impacts, already estimated to be low, would be reduced to non-existent.

f. Deferral Recommended by

State of New York

The Nantucket to Ambrose Navigation Lane

a. Geographic Description

This candidate encompasses 226 blocks and covers an area of 1,286,659 acres (520,704 hectares). This area lies south-southeast of Nantucket Island in water depths between approximately 60 and 100 m. It lies between 80 and 155 statute miles from southern New England.

b. Sales (and date held) for which the Subarea was Studied and Disposition in Each Sale

Nantucket to Ambrose Navigation Lane:

- o Studied in Sale 82 EIS
- o Deferred from Sale 82 Part I to Sale 82 Part II (82 Part II cancelled 12/31/84)

c. Oil and Gas Resource Potential

This subarea contains large Triassic rift-basins and associated stratigraphic traps. A few structures do occur, notably in the eastern part of the subarea.

Data coverage is sufficient to delineate specific prospects and regional trends.

Since the subarea is largely underlain by high risk Triassic rift-basins and a few structural traps, it is not considered as prospective as similar continental shelf acreage that lies to the east of the subarea. However, within the subarea prospectiveness is shown to increase toward the eastern and southeastern parts.

d. Description of the Environment

This navigation lane/USCG Precautionary Area consists of the southern extremes of Nantucket Shoals, Great South Channel and southern portions of Georges Bank. The waters are considered to contain nutrient rich upwellings supporting sport and commercial fishing industries. Various populations of sea ducks are known to winter in the shoals. The endangered humpback whale has been sighted along the 100 m contour from May to November.

e. Potential Impacts Avoided by Deferral of this Subarea

No substantial change in impact to water quality would occur.

Deferral of this area would provide local protection for a number of resources or protected species by removing any potential platforms or oil spills within the area. The deferral however, would not reduce the expected low regional impact.

f. Deferral Recommended by

State of New York

North Atlantic Planning Area

Canyon Area Tracts Deferral in Sale 82

a. Geographic Description

This candidate encompasses 120 blocks and covers an area of 683,182 acres (276,480 hectares). This area includes tracts lying at or near the heads of Alvin, Atlantis, Munson, Nygren, Corsair, Powell, Lydonia, Hydrographer, Oceanographer, Welker, Gilbert, and Veatch Canyons. All of these tracts lie on the outer shelf or upper continental slope regions of Georges Bank. These tracts are situated approximately 110 to 170 miles offshore southeastern New England.

b. Sales (and date held) for which the Subarea was Studied and Disposition in Each Sale

o Canyon Area tracts deferral from Sale 82

c. Oil and Gas Resource Potential

Acreage delimited by this subarea occurs physiographically atop the outer shelf, slope, and continental rise. All but one of the canyon areas cover parts of the Jurassic/Cretaceous paleo-shelf edge carbonate buildup trend. The deeper water segments of most include the regionally defined stratigraphic trap zone where sediments are seen to onlap the paleo-slope surface.

Data coverage is sufficient to define specific prospects, plays, and stratigraphic traps as well as structural and stratigraphic trends.

The subarea is located atop the exploration trend related to the Jurassic/Cretaceous paleo-shelf edge.

Association with the paleo-shelf edge carbonate buildup makes the deeper water parts of the subarea highly prospective with regard to oil and gas potential. In contrast, the shallower water parts, being more remote from this buried shelf edge complex, are considered less prospective, although a few structures do occur.

d. Description of the Environment

Canyon areas are unique because they support biological assemblages which are higher in terms of species diversity and abundance than non-canyon areas of comparable depth along the shelf-break zone. Important commercial species include tilefish, red hake, red crab, lobster, short-finned squid, and Atlantic cod. Sediment transport flows vary within each canyon area.

e. Potential Impacts Avoided by Deferral of this Subarea

No substantial change in water quality impact would occur.

Potential impacts by placement of oil rigs, sedimentation of drilling muds and cuttings, and local impacts to resident fisheries would be avoided with a deferral of this subarea.

f. Deferral Recommended by

State of New York

All Blocks in Water Depths greater than 3,000 meters (North Atlantic)

a. Geographic Description

This candidate encompasses 1,756 blocks and covers an area of 9,997,231 acres (4,045,824 hectares). These blocks lie in the southeastern corner of the planning area in water depths as great as 4,500 m, and are approximately 190 to 350 statute miles from the coast of southeastern New England.

b. Sales (and date held) for which the Subarea was Studied and Disposition in Each Sale

Blocks in water depths greater than 3,000 meters, north Atlantic:
- o Not studied as an alternative at the EIS stage
- o Offered in Sale 82 (Part I cancelled 9/84)

c. Oil and Gas Resource Potential

This subarea is restricted to deep water acreage of the continental rise. Except for widely spaced USGS lines and a few short industry lines, data coverage is sparse to essentially non-existent within this area. Therefore, oil and gas potential is unknown.

d. Description of the Environment

Studies have demonstrated a decrease in faunal density with depth and distance from shore. Polychaetes and Crustacea have the highest densities with polychaetes decreasing with distance from the continental shelf as crustaceans increase. Deep-water fish are primarily rattails, Brotulidae and species of deep-sea sharks. It is not an area of commercial fishing.

e. Potential Impacts Avoided by Deferral of this Area

No substantial change in impact to water quality would occur.

Possible impacts in this area because of OCS activities would be limited primarily to the benthos. With an approximate density of 55 animals/m^2 possible local impacts would be low. Deferral of this area would provide little to no avoidance of regional or local impacts.

f. Deferral Recommended by

Chevron

Low-Industry-Interest Tracts (Sale 111 Area Identification)

a. Geographic Description

This candidate encompasses 3,062 blocks and covers an area of 17,432,529 acres (7,054,848 hectares). These tracts are situated on the inner and mid-shelf portion of the mid-Atlantic in water depths out to approximately 100 m, extending from the three geographical mile line to about 75 statute miles offshore. Another section of low industry interest tracts lies in deep water, about 120 to 160 miles offshore, in water depths from approximately 2,000 m to more than 3,000 m.

b. Sales (and date held) for which the Subarea was Studied and Disposition in Each Sale

Low industry interest tracts (Sale 111 Area ID):

- ° Not studied as an alternative at the EIS stage
- ° Deferred at Area ID stage--Sale 111

c. Oil and Gas Resource Potential

The subarea occurs outside of the area of thickest sediment accumulation (i.e., Baltimore Canyon Trough) beneath the Mid-Atlantic continental margin. Total sediment thicknesses within the subarea are generally 25,000 feet or less.

Triassic rift-basins appear to be present within the nearshore parts of the subarea; further offshore, a few structures are included in the deeper water parts of the subarea.

Data coverage within the nearshore area is essentially non-existent and further offshore, coverage is restricted to widely-spaced USGS lines. Overall, the paucity of data within the subarea presently precludes identification of additional structures and/or stratigraphic traps as well as potential exploration or discovery trends. Oil and gas potential of this subarea of low industry interest is, at present unknown.

d. Description of the Environment

The Mid-Atlantic inner and central shelf benthic habitat is a poorly sorted, medium-to-coarse sand environment, which supports a medium high density and diversity epifauna and infauna. Mesoscale patterns of distribution are evident and related to surficial sand waves, with higher densities being found in the swales. A number of commercial invertebrate species are present including ocean quahog, surf clam, and scallops. Fish species, because of the seasonal environmental extremes of the area, are generally not resident but migrate into the area from the North

or South Atlantic regions. Fish biomass and diversity greatly increase in the late spring and summer seasons with many of the species spawning pelagic eggs during this time. Many commercially and recreationally important finfish species are found in this area, including: flounders; gadids (cod, hakes); sciaenids (spot, croaker, weakfish); and menhaden.

The deeper low-industry-interest tracts (between 2,000 and 3,000m) are faunally depauperate compared to the shelf areas. These depths represent the Continental Rise area and are typified by fine, soft sediments and cold water (<3.5°C). The fauna in this region is represented primarily by infaunal annelids (polychaetes), epibenthic echinoderms (brittle stars, sea cucumbers), and benthopelagic fish (primarily Coryphaenoides armatus). No commercially important species are present.

e. Potential Impacts Avoided by Deferral of this Subarea

This subarea deferral would eliminate virtually all potential for onshore visual impacts to the coasts of Long Island and northern New Jersey resulting from offshore drilling facilities. The risk of impacts to coastal recreation areas from platform spills would also be slightly reduced.

The overall impact to water quality would not change. However, the potentially high impact of a large oil spill to local coastlines, and especially embayments, would be reduced to a moderate level. Water quality impacts due to routine discharges (muds and cuttings, formation water, sanitary/domestic wastes) would still be localized and generally low.

Because of the low industry interest in these areas, the potential for industry-related impacts is low. In the shallower low-industry-interest areas, standard operational impacts which would be avoided are burial of benthic fauna by drilling mud and cuttings discharges, destruction of the benthic habitat by placement of structures, and spatial exclusion of commercial fishery interests from the structure areas. The first two potential impacts would be extremely localized and negligible based upon the low number of leases expected in a low-industry-interest area. The other two potential impacts are also localized but the decrease in potential impacts in the shallower area is not expected to decrease the overall impact level, which is minor. Deferral of the deeper low-industry-interest tracts would remove the potential impacts to the benthic habitat by destruction or burial in the immediate vicinity of the well head.

f. Deferral Recommended by

State of New Jersey

Mid-Atlantic Planning Area

Major Shipping Lanes (Sale 111, Visual No. 5)

a. Geographic Description

This candidate encompasses 235 blocks and covers an area of 1,337,898 acres (541,440 hectares). The major shipping lanes within the mid-Atlantic include Traffic Separation Schemes (TSSs) established by the U.S. Coast Guard. These are, a TSS lying south of Rhode Island controlling access into Narragansett and Buzzards Bay, a TSS lying southeast of New York City controlling access into Delaware Bay, and a small TSS north of Virginia Beach controlling access into the Chesapeake Bay.

b. Sales (and date held) for which the Subarea was Studied and Disposition in Each Sale

Major shipping lanes (TSS):

- Not studied as an alternative at the EIS stage
- Deferred by 50 mile deferral--Sale 111 Area ID

c. Oil and Gas Resource Potential

A Triassic rift-basin has been documented within this subarea, however, no structural or stratigraphic traps have been identified as yet. Existing data are virtually non-existent but structural and stratigraphic traps may occur locally.

Possible exploration trends associated with this subarea cannot be identified given the lack of data. Petroleum potential is unknown; however, the northernmost part of the subarea is thought to be more prospective then the southernmost parts.

d. Description of the Environment

The coastal areas in which these subareas are located are typically higher in phytoplankton and zooplankton biomass than the rest of the shelf. The New York Apex section of this deferral candidate is reported to have high bacterial counts, the most contaminated sediment, and the most acute and extensive alterations of the benthic ecosystems. No noticeable difference from other near-coastal areas has been noted for the Delaware Bay and Chesapeake Bay areas. The areas in this subarea deferral candidate would contain extremely large numbers of anadromous fish species (striped bass, shad, alewife, etc.) and species which use the estuaries as nursery or feeding areas (menhaden, bluefish, spot, etc.) during the spring and fall migrations. Numerous shore, marine, coastal, and waterfowl species--including the endangered peregrine falcon--occur in these areas.

e. Potential Impacts Avoided by Deferral of this Subarea

This subarea deferral would reduce the potential for onshore visual impacts to portions of the coasts of Rhode Island, New Jersey, eastern Long Island, and Delaware resulting from offshore drilling facilities. The risk of impacts to coastal recreation areas from platform spills would also be reduced.

No substantial change in impact to water quality would occur.

Selection of this deferral candidate would greatly decrease the potential impacts to the fauna that use the area as a migration route. The potentially major impacts to the proximate estuarine systems would be appreciably reduced and the probability of vessel accidents in the area caused by OCS activities would be removed.

f. Deferral Recommended by

State of New Jersey

Mid-Atlantic Planning Area

Within 50 Statute Miles from Coastline (New Jersey and Virginia)

a. Geographic Description

This candidate encompasses 1,878 blocks and covers an area of 10,691,799 acres (4,326,912 hectares). This area would include all the blocks on the continental shelf that lie within 50 statute miles of the New Jersey and Virginia coasts. It would include tracts in water depths of up to approximately 80 m.

b. Sales (and date held) for which the Subarea was Studied and Disposition In Each Sale

Within 50 miles of coast (NJ/VA):

° Studied in Sale 76 EIS; later deferred
° Deferred at Sale 111 Area ID

c. Oil and Gas Resource Potential

The eastern part of this subarea encompasses the western half of the Baltimore Canyon Trough sedimentary basin where, locally, total sediment thickness may exceed 50,000 feet. Triassic rift-basins containing stratigraphic traps appear to be present within the subarea although no structural traps have been mapped. An early Jurassic shelf edge stratigraphic trend lies subparallel to and within the easternmost part of the subarea.

A possible exploration trend consisting of both structural and stratigraphic traps associated with the Jurassic/Cretaceous shelf edge complex is located off the eastern edge of the subarea.

Except for a small area off Virginia, data coverage within the subarea is nearly non-existent. Locally, some nearshore areas have no data coverage at all.

Some parts of the subarea appear to be not as prospective as other subareas in the planning area. Elsewhere, prospectiveness cannot be determined because of lack of data.

d. Description of the Environment

This subarea is coincident with much of the shallow low-industry-interest subarea deferral candidate and is generally an area of poorly-sorted, medium-grain-size sand. Many of the valuable commercial fisheries--such as surf clam, ocean quahog, menhaden, and scallops--are found in the area but no determinate, highly-productive biological areas are present. Approximately ten species

of marine birds are common in the subarea and many additional species--including one endangered species, the peregrine falcon--migrate seasonally through the subarea. A number of species of marine mammals are found in this subarea, and of the six endangered cetaceans reported in the mid-Atlantic region, two--the right whale and the fin whale--are most likely to occur in this subarea. Sea turtles are seasonally present in the mid-Atlantic and two endangered species (leatherback and Atlantic ridley turtles) and one threatened species (loggerhead turtle) are likely to be transients in the subarea. The endangered hawksbill turtle and the threatened green sea turtle also may be present.

e. Potential Impacts Avoided by Deferral of this Subarea

This subarea deferral would eliminate all potential for onshore visual impacts to the coasts of New Jersey, Delaware, Maryland, and Virginia resulting from offshore drilling facilities. The risk of impacts to coastal recreation areas from platform spills would also be substantially reduced.

Potentially high water quality impacts to local coastlines and embayments resulting from a large oil spill would be reduced to a moderate level.

Deferring this subarea would reduce local impacts to the benthic community and prevent impacts to commercial fisheries resulting from spatial exclusion by drilling rigs or platforms. However, no change in overall impact levels is expected. The potential impacts to endangered or threatened birds, turtles, and cetaceans in the mid-Atlantic region would remain unchanged if this subarea were deferred. However, local impacts to endangered or threatened species would be removed. If this deferral option is adopted, the probability of an impact to shallow water or coastal areas resulting from a mid-Atlantic lease sale would be reduced, but no appreciable decrease in regional impact level would occur.

f. Deferral Recommended by

State of New Jersey, State of Virginia

Mid-Atlantic Planning Area

Within 12 Miles of Delaware's Territorial Waters (Within 15 Miles of Coast)

a. Geographic Description

This candidate encompasses 73 blocks and covers an area of 415,602 acres (168,192 hectares). This area would include tracts lying east of the State of Delaware extending from the three-geographical-mile line out to an approximate water depth of 15 m.

b. Sales (and date held) for which the Subarea was Studied and Disposition In Each Sale

Within 15 miles of coast (Delaware):

- Not studied as an alternative at the EIS stage
- Deferred by 50 mile deferral--Sale 111 Area ID

c. Oil and Gas Resource Potential

Data coverage within the nearshore areas is essentially non-existent and further offshore, coverage is restricted to widely-spaced USGS lines. Overall, the paucity of data within the subarea presently precludes identification of additional structures and/or stratigraphic traps as well as potential exploration or discovery trends. Oil and gas potential of this subarea is, at present, unknown.

d. Description of the Environment

This subarea consists of a shallow marine environment of medium-grain sand sediment. The primary infaunal and epifaunal groups found in the area are annelid worms (polychaetes), mollusks (surf clam, ocean quahog), echinoderms (sand dollars, starfish), and crustaceans (lobsters, crabs). A number of marine birds, waterfowl, and coastal species may be found in, or migrating through, the area. The endangered peregrine falcon migrates through the area seasonally and threatened or endangered sea turtles, and endangered cetaceans may occasionally be sighted in the area.

e. Potential Impacts Avoided by Deferral of this Subarea

This subarea deferral would reduce but not eliminate the potential for onshore visual impacts to the coasts of Delaware, New Jersey, and Maryland resulting from offshore drilling facilities. The risk of impacts to coastal recreation areas from platform spills would also be slightly reduced.

Overall impacts to water quality would not change. However, potentially high impacts from a large oil spill to the local Delaware coastline and embayments would be reduced to a moderate level.

If this subarea deferral candidate is selected, the potential impacts to the local fauna would be appreciably reduced. However, overall potential impacts to regional population levels of invertebrates, fish, birds, marine mammals, and turtles will not decrease.

f. Deferral Recommended by

State of Deleware

Shoreward of the 200-meter Isobath off North Carolina

a. Geographic Description

This candidate encompasses 557 blocks and covers an area of 3,171,103 acres (1,283,328 hectares). This area includes all blocks off North Carolina extending from the three-geographical-mile line out to the 200-m contour, approximately 35 miles from shore.

b. Sales (and date held) for which the Subarea was Studied and Disposition In Each Sale

Shoreward of 200 meters (North Carolina):

- Not studied as an alternative at the EIS stage
- Deferred--Sale 111 Area ID

c. Oil and Gas Resource Potential

Triassic rift-basins occur within this subarea and are part of the same trend of rift-basins noted elsewhere along the nearshore zone of the planning area. Along the eastern edge, the subarea flanks the paleo-shelf edge carbonate buildup described earlier and locally includes some structural traps. This area also includes parts of the Carolina Trough sedimentary basin, an area of thick sediment accumulation.

Data coverage within the subarea is virtually non-existent over most of the nearshore acreage, is sufficient in the central parts to define specific prospects, and is sufficient along the eastern parts to determine specific prospects and plays as well as stratigraphic and structural trends.

The eastern part of the subarea is prospective because of its close proximity to a potential exploration trend associated with the paleo-shelf edge complex. Elsewhere, the acreage within the subarea is considered not as prospective. A few nearshore areas have no data at all, thus prospective areas cannot be determined.

d. Description of the Environment

This subarea includes a major Atlantic faunal transition zone, which is located approximately at Cape Hatteras and is an area of delineation between northern boreal and southern temperate fauna. This subarea is generally a high-energy one in which the Gulf Stream dominates the southern part but decreases in influence towards the north. Many fish species including menhaden, croaker, spot, and bluefish migrate through this area during the spring and fall and are found in great numbers at

these times. Because of the medium to high energy environment in this subarea, the infaunal species are predominated by filter and suspension feeders (typically polychaetes and mollusks). Most of the individuals of the five threatened or endangered turtle species that occur in the Mid-Atlantic (see subarea deferral candidate no. 10) migrate through this area during spring and fall. Endangered cetaceans which migrate seasonally to the south Atlantic (humpback and right whales) probably traverse this subarea.

e. Potential Impacts Avoided by Deferral of this Subarea

This subarea deferral would remove virtually all of the potential for onshore visual impacts to coastal North Carolina resulting from offshore drilling facilities. The risk of impacts to coastal recreation areas from platform spills would also be reduced.

Overall impacts to water quality would not change substantially. However, the potentially high impact from a large oil spill to local North Carolina coastlines, and especially embayments, would be reduced to a moderate level.

Deferral of this subarea could appreciably reduce the impacts to species that migrate to the South Atlantic region. Because of the relatively high energy of most of the subarea, impacts resulting from the discharge of drilling muds and cuttings and formation waters would be minimal. However, Gulf Stream filaments, or frontal eddies, may entrain and transport an accidental oil spill close to shore or maintain it in the area where it could sublethally or lethally affect, modify the routes of, or reduce the prey of the various migrating species as they pass though the area. Selection of this subarea deferral candidate would substantially reduce the probability of impacts to coastal North Carolina.

f. Deferral Recommended by

State of North Carolina

Mid-Atlantic Planning Area

Submarine Lanes, Ocean Disposal Sites (Sale 111 FEIS)

a. Geographic Description

This candidate encompasses 1,066 blocks and covers an area of 6,068,934 acres (2,456,064 hectares). Two major submarine transit lanes exist within the Mid-Atlantic Planning Area. One lies southeast of the tip of Long Island, approximately 15 miles away and extending due south into about the 3,000-m water depth. A small transit lane lies due east of the southernmost portion of the previously mentioned transit lane. Another submarine transit lane lies due east of Virginia Beach, beginning approximately 65 miles from shore and extending outward to the east northeast, and south into deeper waters.

There are presently several active ocean disposal sites. Active sites for acid waste, cellar dirt, sewage sludge (being phased-out), and wood incineration exist within the New York Bight Apex, southeast of New York City. Other active disposal sites are: the Deepwater Municipal Sludge Site located approximately 120 nautical miles southeast of Ambrose Light and 115 nautical miles from Atlantic City in water depths ranging from 2,250 to 2,750 m, and the Deepwater Industrial Waste Site located 125 nautical miles southeast of Ambrose Light and 105 nautical miles from Atlantic City in water depths ranging from 2,250 to 2,750 meters.

b. Sales (and date held) for which the Subarea was Studied and Disposition In Each Sale

Submarine Transit Lanes and Ocean Disposal sites (Sale 111 FIES):

- Not studied as an alternative at the EIS stage
- Submarine transit lanes deferred--Sale 111 Area 10
- Ocean disposal sites offerred in Sale 76 and proposed Sale 111

c. Oil and Gas Resource Potential

The shallow-water ocean disposal sites are located where Triassic rift-basins appear to be present within the subarea. The deep-water disposal sites are positioned seaward of the Jurassic/Cretaceous paleo-shelf edge exploration trend.

The submarine transit-lane corridor located in the northernmost part of the planning area cuts across the Jurassic/Cretaceous paleo-shelf edge carbonate buildup as well as contiguous trends of structural and stratigraphic trapping. The submarine transit-lane corridors located in the central and southern parts of the planning area also transect, although locally, the same carbonate buildup-, stratigraphic-, and structural-trends noted in the north. In addition, these southern corridors occur at or near the axis of the Baltimore Canyon Trough where total sediment thickness may approach 45,000 feet.

Data coverage in the northernmost submarine transit-lane corridor is sufficient in the northern part (shelf acreage) to define specific prospects and in the central part (continental shelf, slope, and rise acreage) to delineate specific prospects, plays, and trends. However, in the southern part (rise acreage) data coverage is sparse to non-existent. Data coverage in the southernmost submarine transit lane corridors is largely non-existent except along the landwardmost edge where coverage is sufficient to define specific prospects, plays, and trends.

Data coverage with regard to ocean disposal sites is essentially non-existent and further offshore, coverage is restricted to widely-spaced USGS lines. Overall, the paucity of data within the ocean disposal sites presently precludes identification of additional structures and/or stratigraphic traps as well as potential exploration or discovery trends. Thus, the oil and gas potential of the ocean disposal sites within this subarea is, at present, unknown.

Within this subarea, prospective acreages (from the point of view of both the Atlantic Region and industry) are restricted to the central part of the northern submarine corridor and to the northwesternmost parts of the southern submarine corridors. Elsewhere, the oil and gas potential is largely unknown.

d. Description of the Environment

The submarine transit lanes and ocean disposal sites contained in this subarea include all of the various ecosystems and habitats found in the mid-Atlantic region such as: shallow inner shelf, outer shelf, shelf break zone, canyon (Norfolk), continental slope, and continental rise. All of the typical mid-Atlantic faunal constituents would be found in this subarea. All of the threatened or endangered species occurring in the mid-Atlantic (peregrine falcon, Atlantic Ridley turtle, loggerhead turtle, hawksbill turtle, leatherback turtle, green sea turtle, fin whale, sei whale, humpback whale, right whale, sperm whale, blue whale) could use parts of this subarea for feeding, migrating, or breeding/calving.

e. Potential Impacts Avoided by Deferral of this Subarea

Adopting this deferral would preclude potential area use conflicts between OCS oil and gas activities and active ocean dumping. However, this does not seem to be a substantial impact reduction in that the mitigation of this use conflict can occur through planning and coordination. No substantial change in water quality impact would occur.

Although this deferral candidate encompasses a sizable area (1,066 blocks) the amount of each specific habitat that may be affected is relatively low in comparision to the remaining planning area. In addition, the probability that a major oil spill would occur or move into the subarea would change very little, thereby dictating only a small decrease in impact level.

f. Deferred Recommended by

State of North Carolina

Mid-Atlantic Planning Area

National Marine Sanctuaries (U.S.S. Monitor)

a. Geographic Description

This candidate encompasses 2 blocks and covers an area of 11,386 acres (4,608 hectares). The U.S.S. Monitor National Marine Sanctuary lies approximately 16 miles southeast of Cape Hatteras in Blocks NI 18-2, 939 and 983. Sites on the site evaluation list include the Virginia/Assateague Island Area due east of Assateague Island.

b. Sales (and date held) for which the Subarea was Studied and Dispositio in Each Sale

National Marine Sanctuaries (U.S.S. Monitor):

- Studied in Sale 78 EIS
- Never leased

c. Oil and Gas Resource Potential

Data coverage within the subarea is virtually non-existent over most of the nearshore acreage, thus prospective areas cannot be determined.

d. Description of the Environment

The area is the site of the historical wreck of the ironclad U.S.S. Monitor. Although this is a fairly high energy area, some attached epifaunal and epifloral species are present. A single colony of the scleractinean coral, Oculina arbuscula, has been reported on the wreck, which is apparently its northern limit. The fauna is dominated by mollusks, annelids, and the primarily migratory fish that seasonally move through the area.

e. Potential Impacts Avoided by Deferral of this Subarea

OCS exploration activities which might raise concern about the stability and security of the U.S.S. Monitor wreck include high resolution profiling, disposal of drilling muds and cuttings, structural placements on the ocean floor, and oil spills. None of these activities, however, pose any substantial threat to the U.S.S. Monitor.

High resolution profiling in the area of the Monitor site has not been shown to accelerate deterioration of the wreck. Disposal of muds and cuttings from drilling platforms, if located in proximity to the Monitor wreck could increase the sediment load to the site. Chances are very remote that a surface oil spill could be entrained in the water column deeply enough to affect the U.S.S. Monitor site, however a subsurface blowout could pose a substantial risk to the marine sanctuary.

No substantial change in impacts to water quality would occur.

f. Deferral Recommended by

State of North Carolina

Buffer Zone Around the Monitor Marine Sanctuary (Sale 111 FEIS)

a. Geographic Description

This candidate encompasses 4 blocks and covers an area of 22,772 acres (9,216 hectares). The buffer zone around the Monitor Marine Sanctuary consists of a vertical water column, 1 nautical mile in diameter, extending from the surface to the seabed, the center of which is at 35°00'23"N latitude and 75°24' 32" W longitude.

b. Sales (and date held) for which the Subarea was Studied and Disposition in Each Sale

Buffer zone around Monitor:

- Studied as an alternative in Sale 78 EIS
- Never leased

c. Oil and Gas Resource Potential

This subarea has no data at all, thus prospective areas cannot be determined.

d. Description of the Environment

This subarea is in a well-sorted sand environment of approximately 60-m water depth. This candidate is located within the bounds of subarea delection candidate No. 1 and would share the same faunal constituents. At the center of the subarea is the wreck of the U.S.S. Monitor, a National cultural resource.

e. Potential Impacts Avoided by Deferral of this Subarea

This subarea deferral would further decrease the likelihood of damage to the U.S.S. Monitor wreck resulting from OCS oil and gas activities in the proximate area and/or oil spills as descibed under subarea deferral 13.

Deferral of this subarea would have a negligible effect on the potential impacts to biological resources of the planning area. However, local impacts would be mitigated.

f. Deferral Recommended by

State of North Carolina

Canyon head areas (Area ID Canyon Blocks Deleted Plus Sale 111 FEIS, Alternative 5 Plus Sale 111 SID

a. Geographic Description

This candidate encompasses 164 blocks and covers an area of 933,682 acres (377,856 hectares). This area includes whole or partial blocks located within or around the canyon areas, flanks, and axes of Block, Hudson, Toms, Carteret, Lindenkohl, Spencer, Wilmington, Baltimore, Accomac, Washington, and Norfolk Canyons. These blocks lie from approximately 65 to 150 miles offshore in water depths ranging from approximately 100 to 900 m.

b. Sales (and date held) for which the Subarea was Studied and Disposition in Each Sale

Canyonhead areas:

- Studied in the following EISs:
  Sales 49, 59, 76, 111
- Offered in the following sales:
  49, 59, RS-2
- 14 leases as a result of Sale 49; no leases from 59 or RS-2
- Deferred from the following Sales: 76 and 111

c. Oil and Gas Resource Potential

Acreages within this subarea, which locally includes parts of subareas C and E, are underlain by parts of the Jurassic/Cretaceous paleo-shelf edge carbonate buildup trend. The deeper water parts of some canyon head areas are located at or near the regionally defined stratigraphic trap zone associated with sediment onlap against the paleo-slope surface.

Data coverage within the subarea is virtually non-existent over most of the nearshore acreage, is sufficient in the central most parts to define specific prospects, and is sufficient along the eastern parts to determine specific prospects and plays as well as stratigraphic and structural trends.

The eastern part of the subarea is prospective because of its close proximity to a potential exploration trend associated with the paleo-shelf edge complex. Elsewhere, the acreage within the subarea is considered not as prospective. A few nearshore areas have no data at all, thus prospective areas cannot be determined.

d. Description of the Environment

The middle Atlantic continental slope physiography is dominated by numerous submarine canyons which cut into the slope in varying degrees. The major canyons along the Middle Atlantic Bight incise deeply into the shelf (up to 150 km shoreward from the shelf edge), while the minor canyons are located on the upper and middle slope, or barely reach the shelf edge.

Because of the past or present erosional nature of the canyon head areas, the topography tends to be very rugged and highly diverse. The outcroppings formed by the more consolidated sediments provide a greater amount of attachment substrate than is typically found along the rest of the continental margin. Although, in general, the biomass and numbers of organisms decrease in a seaward direction from the outer shelf to the slope and beyond, submarine canyons have been shown to have increased biomass and numbers of organisms. The primary reason for increased density is the complex topography located at the canyon heads and along the shear walls. In conjunction with increased niche space because of topographic complexity, increased attachment substrate--in the form of consolidated sediment or rock scarps--allows sessile invertebrates to colonize these areas, thereby increasing the number of available niches for other fauna which may associate with these colonies.

Recent research has indicated that canyons, in general, with their increased exposure of outcrops have large populations of attached filter-feeding species, while the comparable slope areas are dominated by mobile scavengers. The increased density of filter feeders in canyons also supports the hypothesis that the canyons are conduits for particulates (including particulate organics) from the continental slope to the abyss.

Coral populations tend to be more diverse in middle Atlantic canyon habitats than the adjacent slope areas. The primary reason for increased diversity in the canyons is that those species restricted to hard substrates are found only in canyons, but soft-substrate types are found both in the canyons and on the slope.

e. Potential Impacts Avoided by Deferral of this Subarea

No substantial change in impacts to water quality would occur.

The mechanical damage that results from the placement of structures such as pipelines, well complexes, platforms, and wellheads is highly localized and would be avoided in the major canyon areas under this subarea deferral.

The greatest impact avoided results from mechanical damage which could occur in the "pueblo village" areas of canyon heads. These areas are extensive burrow systems that support a number of species such as tilefish, lobster, red crab, and cancer crabs. They would be highly susceptible to mechanical damage resulting from structure placement.

Chronic discharges of mud and cuttings pose little threat to canyon systems. Acute discharges which would be expected to cause the greatest impact would be avoided. Spudding of the well and detachment of the riser could release drilling muds and cuttings directly at the sea floor. It is estimated that about 744 m^2 of sediment surface could be covered by up to 1 m of drill muds and cuttings during initial well drilling. No estimate of areal coverage is available for riser detachment.

Surface oil spills should have no major impact on canyon areas because of the water depths of the areas. Petroleum hydrocarbons can reach the canyon areas by adsorption onto particulates that may settle out of the water column to the canyons, or by incorporation into zooplankton fecal pellets which then sink to the bottom. In both these cases, the impact on the canyon areas is expected to be negligible because of the dispersed nature of the particles. A subsurface oil spill within a canyon, however, could pose an appreciable threat to the biota in its vicinity. This potential impact would be avoided in canyon systems deferral under this option.

f. Deferral Recommended by

State of Deleware, State of New Jersey, State of North Carolina

Mid-Atlantic Planning Area

NASA Wallops Island Flight Center at Wallop's Island Virginia (Approximately 380 Blocks)

a. Geographic Description

This candidate encompasses 510 blocks and covers an area of 2,903,523 acres (1,175,040 hectares). This area is a large zone situated east of Accomack, Virginia. It extends from the three-geographical-mile line out to an approximate water depth of 1,200 m; about 80 miles from shore.

b. Sales (and date held) for which the Subarea was Studied and Disposition in Each Sale

NASA Wallop's Island Flight Center at Wallop's Island, Virginia:

- Studied in Sale 111 EIS
- Deferred from Sale 76
- Deferral alternative in Sale 111

c. Oil and Gas Resource Potential

The eastern part of this subarea encompasses the western half of the Baltimore Canyon Trough sedimentary basin where total sediment thickness, locally, may exceed 50,000 feet. Triassic rift-basins containing stratigraphic traps appear to be present within the subarea although no structural traps have been mapped. An early Jurassic shelf edge stratigraphic trend lies subparallel to and within the easternmost part of the subarea.

A possible exploration trend consisting of both structural and stratigraphic traps associated with the Jurassic/Cretaceous shelf edge complex is located off the eastern edge of the subarea.

Except for a small area off Virginia, data coverage within the subarea is nearly non-existent. Locally, some nearshore areas have no data coverage at all.

Some parts of the subarea appear to be not as prospective as others within the planning area. Elsewhere, prospectiveness cannot be determined because of lack of data.

d. Description of the Environment

This subarea predominantly consists of continental shelf habitat and some slope habitat. The shelf waters are relatively low in salinity and are subject to strong seasonal cooling or warming, and tidal effects. This subarea is important as part of the habitat

for development of fish eggs and larvae, but no distinct spawning areas are evident. The benthic habitat is characterized by medium-grained sand inshore, grading to finer sediments offshore. A ridge-and-swale mesoscale topography is apparent on the inner and outer portions of the shelf. Polychaetes and mollusks dominate on the shelf, but decrease in importance seaward as the numerical dominance of crustaceans increases.

e. Potential Impacts Avoided by Deferral of this Subarea

This subarea deferral would eliminate all potential for onshore visual impacts to the Delmarva portion of the Virginia coast resulting from offshore drilling facilities. The risk of impacts to coastal recreation areas from platform spills would also be slightly reduced.

No substantial change in impact to water quality would occur.

No significant potential impacts would be expected on this area's biological functions. Therefore, deferral of this area would maintain the already negligible impacts expected.

f. Deferral Recommended by

State of North Carolina, National Aeronautics and Space Administration

Mid-Atlantic Planning Area

All Blocks in Water Depths greater than 3,000 meters (Mid-Atlantic)

a. Geographic Description

This candidate encompasses 7,119 blocks and covers an area of 40,529,776 acres (16,402,176 hectares). These blocks lie in the far eastern and southeastern portion of the planning area in water depths as great as 5,000 m. They lie as close as 60 statute miles from Cape Hatteras and as far as 450 statute miles from Atlantic City, New Jersey.

b. Sales (and date held) for which the Subarea was Studied and Disposition in Each Sale

Blocks in water depth greater than 3,000 meters, Mid-Atlantic:

- Not studied as an alternative at the EIS stage
- Previously offerred in Sales 59 and 76 with no leases issued

c. Oil and Gas Resource Potential

Except for widely-spaced USGS lines, data coverage is sparse. Therefore, oil and gas potential in unknown.

d. Description of the Environment

Benthic and epibenthic species are found at these great depths, however, densities decrease dramatically from the slope down.

Small annelids and crustaceans comprise the majority of the animals found.

e. Potential Impacts Avoided by Deferral of this Subarea

No substantial change in impacts to water quality would occur.

Due to the great water depth and distance from land, potential impacts due to OCS activities are negligible. Deferral of this subarea would avoid these negligible impacts.

No substantial change in water quality impact would occur.

f. Deferral Recommended by

Chevron

South Atlantic Planning Area

All Areas South of the Flight Clearance Zone including the Straits of Florida

a. Geographic Description

This candidate encompasses 1,003 blocks and covers an area of 5,710,263 acres (2,310,912 hectares). This area includes all blocks lying off the coast of Florida, south of Fort Pierce, beginning at approximately 27°30'N latitude and extending southward.

b. Sales (and date held) for which the Subarea was Studied and Disposition in Each Sale

All areas south of Flight Clearance Zone including Straits of Florida:

- Studied in Sales 78 and 90 EISs
- Deferred in Sales 78 and 90

c. Oil and Gas Resource Potential

Data coverage is very sparse to non-existent. Petroleum potential is unknown; however, Triassic basins are known to occur along this part of the inner margin.

d. Description of the Environment

The area consists of fine sandy areas graduating to coarser grains and patches of coral reefs. These areas support small tropical fish and commercial fish and invertebrates. The deeper waters support a commercial and sport fishing industry. Manatees are known to occur in the coastal and inland waterways during the winter. During summer months, manatees will migrate northward in shallow coastal waters. A large concentration of shipwrecks is located off Biscayne Bay and the Florida Keys. Some of the 21 known Brown Pelican colonies are located in Key West.

e. Potential Impacts Avoided by Deferral of this Subarea

This subarea deferral would eliminate all potential for onshore visual impacts to the south Florida coast resulting from offshore drilling facilities. The risk of impacts to coastal recreation areas from platform spills would also be reduced.

Although this deferral would not substantially change the overall impacts to water quality in the planning area, it would greatly reduce the potential impact from a large oil spill within this Florida deferral area. The potentially high water quality impacts along the coast and especially embayment areas would be reduced to a moderate level. The localized impacts of routine discharges (muds and cuttings, formation water, sanitary/domestic waste) would still be low.

Deferral of this area would eliminate potential impacts to the local communities by the placement of structures and discharge of drilling materials and reduce the probability of an impact from an accidental oil spill. However, the overall impacts to the region would not be appreciably reduced.

f. Deferral Recommended by

State of Florida

South Atlantic Planning Area

National Marine Sanctuary (Gray's Reef)

a. Geographic Description

This candidate encompasses 6 blocks and covers an area of 34,159 acres (13,824 hectares). This area includes blocks containing Gray's Reef National Marine Sanctuary which lies 17.6 nautical miles east of Sapelo Island, Georgia. The sanctuary occupies an area of 16.68 nmi^2.

b. Sales (and date held) for which the Subarea was Studied and Disposition In Each Sale

National Marine Sanctuaries (Gray's Reef):

- Not studied as an alternative at the EIS stage
- Never leased

c. Oil and Gas Resource Potential

This subarea lies shoreward of a trend of structural traps which extend northeastward from the Southeast Georgia Embayment. No data coverage exists over this area and its prospectiveness is unknown.

d. Description of the Environment

The sanctuary is a biologically productive, moderate-to-high relief, live-bottom reef. The reef supports a variety of biota including an array of seaweeds, invertebrates, fish, and turtles. The sanctuary demonstrates the subtropical community profile which is common to all live-bottom areas in the south Atlantic, and is a valuable research area for the study of reef environments.

e. Potential Impacts Avoided by Deferral of this Subarea

No substantial change in impacts to water quality is anticipated.

Deferral of this area would avoid any possible impacts from standard OCS oil and gas operations to Gray's Reef. The potential impacts resulting from an accidental oil spill would be slightly reduced.

f. Deferral Recommended by

State of North Carolina

South Atlantic Planning Area

Delete all tracts in water shallower than 500 meters

a. Geographic Description

This candidate encompasses 5,510 blocks and covers an area of 31,369,443 acres (12,695,040 hectares). This area includes all blocks within the planning area lying in water shallower than 500 meters off the coast of North Carolina, South Carolina, Georgia, and Florida. This contour is as close to shore as 100 miles off Florida and as far as 160 miles off Georgia.

b. Sales (and date held) for which the Subarea was Studied and Disposition In Each Sale

Defer all tracts in water shallower than 500 meters:

- Not studied as an alternative at the EIS stage
- Offered in Sales 43 (43 leases, now expired), 56 (8 leases), RS-2 (2 leases), and 78 (1 lease)

c. Oil and Gas Resource Potential

A trend of predominantly structural traps extending northeastward from the Southeast Georgia Embayment (SGE) and stratigraphic traps associated with as early Mesozoic basin near Cape Canaveral are included in this option. A large part of the Carolina Trough sedimentary basin (area of thick sediment accumulation) lies within the option.

Within the nearshore areas, data coverage is very sparse to non-existent. Elsewhere, except for the central parts that overlie the SGE, and off Cape Romain, South Carolina, data coverage is generally sparse. In other areas of the SGE and locally off South Carolina, data coverage is sufficient to define specific prospects, plays, and structural and stratigraphic trends.

Structural traps and a carbonate paleo-shelf edge trend are found to lie seaward of the 500-m isobath of the northern boundary of the subarea.

The petroleum potential of most of the subarea is still largely unknown; however, the northeastern part is thought to be more prospective than elsewhere because of its proximity to a known structural trend located in deeper water. The greatest percentage of resources is found seaward of the subarea's eastern boundary (i.e., 500-m isobath).

d. Description of the Environment

The environment in the South Atlantic Bight is predominantly live bottoms and soft sands. Live bottoms appear as low, moderate, or high relief reefs. Low-relief live bottoms are generally found between the 15- to 30-m isobaths, are widely distributed across the shelf, and are susceptible to periodic covering by sand veneer. They appear as smooth, flat-lying substrates. These areas can be live bottoms with sparse to moderate occurrence of sessile epibenthos, principally sponges, soft corals (octocorals), and some hard corals. Moderate-relief live bottoms occur as irregular and discontinuous rocky outcrops. Their highest frequency of occurrence is between the 30- to 60-m isobaths; they are generally widespread, but are most commonly found off north Florida and the Carolinas on the middle shelf. These live bottoms may support abundant benthic species (mostly sponges, octocorals, algae, amphipods, polychaetes, and hard corals) and pelagic or reef fish communities. High-relief or shelf-edge reefs are restricted to the shelf edge between approximately the 30- to 100-m isobaths and occur as discontinuous ridges. Live-bottom communities of principally sponges, octocorals, algae, and hard corals occur with the typically associated vertebrate and other invertebrate fauna. Sand or soft bottom areas are scattered. The taxa of major importance are widely distributed, with echinoderms the most commonly observed. Large aggregates of sea urchins and sea cucumbers occur at mid-shelf and shelf edge locations. Fish nesting sites have been observed concentrated below the shelf break off North Carolina. Schooling fish occur over soft- and hard-bottom areas.

The area between 27°30'N to 29°N and 79°56'W to 80°02'W is the only known area for Oculina coral banks which are unique areas providing habitats for many species. Individual colonies exist off North Carolina and on the U.S.S. Monitor. This area is thought to be used by some marine mammals as feeding, breeding and/or calving grounds as well as a migratory route to the north. Species of marine turtles are known to nest on south Atlantic beaches. The loggerhead, green, and Kemp's ridley turtles prefer the shallow coastal waters, but can occur more than 100 mi offshore, which is the preferred area of leatherback turtles.

e. Potential Impacts Avoided by Deferral of this Subarea

This subarea deferral would eliminate all potential for onshore visual impacts to the coasts of North Carolina, South Carolina, Georgia, and Florida, resulting from offshore drilling facilities. The risk of impacts to coastal recreation areas from platform spills would also be substantially reduced.

This deferral would substantially reduce potential water quality impacts which may result from a large oil spill. Potentially high impacts to coastline and especially embayments within the planning area would be reduced to a moderate level.

Deferral of the entire area would avoid possible local impacts on live-bottom assemblages resulting from direct platform placement. Local spillage with possible impacts on fish communities, marine mammals, and turtles would also be avoided. Because of the influence of the powerful Gulf Stream, it would be very unlikely that oil spilled outside this area would be transported into the area, therefore impacts associated with oil spills would be avoided.

f. Deferral Recommended by

Florida Department of Natural Resources

South Atlantic Planning Area

Inner Shelf (Ten Fathom Ledge)--(Sale 90 FEIS, Visual 2 and 2A)

a. Geographic Description

This candidate encompasses 18 blocks and covers an area of 102,477 acres (41,472 hectares). This area lies 17 miles due south of Cape Lookout, North Carolina, and occupies an area of approximately 135 mi^2. It lies at an approximate water depth of 25 m and is bounded by the following coordinates - 34°26'N, 76°37'W; 34°34'N, 76°37'W; 34°20'N, 76°29'W; 34°13'N, 76°29'W.

b. Sales (and date held) for which the Subarea was Studied and Disposition In Each Sale

The Inner Shelf--17 miles south of Cape Lookout (Ten Fathom Ledge):

- Not studied as an alternative at the EIS stage
- Never leased

c. Oil and Gas Resource Potential

The area overlies parts of the Carolina Trough sedimentary basin where total sediment thickness may, in places, exceed 35,000 feet. A few structures have been identified in the seaward parts of this area. Data coverage over most of this area is sparse and present findings suggest that the area is not very prospective.

d. Description of the Environment

The inner-shelf area off North Carolina is primarily soft bottom and low-relief hard bottom. Low-relief hard bottoms can support live bottoms with sparse to moderate occurrence of sessile epibenthos. An abundance of attached macroalgae exist in the area. The area is part of a larger one which runs as a band along the south Atlantic coastline. This band basically defines the inshore fisheries for red drum, weakfish, striped bass, bluefish and kingfish. The major human use of the Ten Fathom Ledge/Big Rock complex is recreational, including SCUBA diving and recreational fishing.

e. Potential Impacts Avoided by Deferral of this Subarea

This subarea deferral would eliminate some of the potential for onshore visual impacts to the Cape Lookout area of North Carolina resulting from offshore drilling facilities. Potential conflicts between oil and gas exploratory activity and recreational use of the area would be avoided by this deferral.

No substantial change in impacts to water quality is anticipated.

Deferral of this area would avoid local impacts on the low relief hard bottom areas and the present fisheries, but would not affect regional impact levels.

f. Deferral Recommended by

State of North Carolina

The Outer Shelf (Big Rock) (Sale 90 FEIS)

a. Geographic Description

This candidate encompasses 9 blocks and covers an area of 51,238 acres (20,736 hectares). This area lies 36 miles south of Cape Lookout and occupies an approximate area of 36 nmi^2. It lies in an approximate water depth of 40-50 m and is bounded by the following coordinates 34°12'N, 76°15'W; 34°7'N, 76°15'W; 34°12'N, 76°10'W; 34°7'N, 76°10'W.

b. Sales (and date held) for which the Subarea was Studied and Disposition in Each Sale

The Outer Shelf--36 miles offshore (Big Rock):

- Not studied as an alternative at the EIS stage
- Never leased

c. Oil and Gas Resource Potential

The area overlies parts of the Carolina Trough sedimentary basin where total sediment thickness may, in places, exceed 35,000 feet.

A few structures have been identified in the seaward parts of this area. Data coverage over most of this area is sparse and present findings suggest that the area is not very prospective.

d. Description of the Environment

Big Rock is an area on the continental shelf break which has several fish populations of commercial importance. This subarea deferral candidate combined with the Ten Fathom Ledge subarea deferral candidate, is on the Site Evaluation List for marine sanctuaries and has been nominated for Preliminary Consultation before being recommended for sanctuary status. This area, although deeper and less diverse than Ten Fathom Ledge, is an example of subtropical populations at their northern extreme.

e. Potential Impacts Avoided by Deferral of this Subarea

No substantial change in impacts to water quality is anticipated.

Deferral of this subarea would prevent the potential major impacts to these unique biological systems. However, no change in regional impact levels is anticipated.

f. Deferral Recommended by

State of North Carolina

Flight Clearance Zone of the Kennedy Space Center

a. Geographic Description

This candidate encompasses 3,814 blocks and covers an area of 21,713,803 acres (8,787,456 hectares). This area lies off the coasts of southern Georgia and northern Florida. It is predominantly located between 31° and 27°N latitude and extends from the immediate coastline eastward out into water depths as great as 2,000 m at approximately 77°W longitude.

b. Sales (and date held) for which the Subarea was Studied and Disposition in Each Sale

The Flight Clearance Zone of the Kennedy Space Center:

- Studied in Sale 78 EIS
- Deferred from Sale 78 and Sale 90

c. Oil and Gas Resource Potential

This subarea includes a large part of the Blake Plateau Basin (an area of thick sediment accumulation that, locally, may exceed 35,000 feet). The subarea is found to contain broad, low relief anticlinal structures that are mostly confined to the central and eastern parts of the subarea.

Over most areas, data coverage is sufficient to define specific prospects. No potential exploration trends have been identified within the subarea.

d. Description of the Environment

The area encompasses parts of the geological features known as the Florida-Hatteras Shelf (400 meters) and Blake Plateau (600 to 1,000 meters). The shelf surface is not flat but characterized by numerous sand ridges which trend at low angles to the coast. Other irregularities include scattered outcrops of live bottoms. The Blake Plateau is generally broad and flat and characterized by terrace like intervals found at 800, 900, 1,000, and 1,100 m. The western margin is characterized by the appearance of live, deep-water coral mounds. The Florida-Hatteras Shelf has been delineated into three subtidal sand-bottom assemblages; 0 to 20 m (turbulent zone), 40 to 120 m (outer continental shelf) and 160 to 205 m (upper continental shelf). The sand dollar *Mellita quinquiesperforata* and polychaetes dominate the turbulent zone. The outer and upper zones are dominated by species of polychaetes and amphipods. The continental slope area is considered to be depauperate in comparison to the shelf.

The deeper region between 400 to 1,000 m is an area known for sport fishing of "blue water" species. Other than some tuna that exhibit schooling behavior, many species occur either singly or in pairs. There also exists distinct deep-water fauna such as anglerfish, rattails, hakes, and deep-sea synaphobranchid eels. Generally, these species are distributed in discrete depth zones.

e. Potential Impacts Avoided by Deferral of this Subarea

This subarea deferral would eliminate any potential for onshore visual impacts to the Florida coast between Cape Kennedy and Daytona Beach resulting from offshore drilling facilities. The risk of impacts to coastal recreation areas from platform spills would also be slightly reduced.

This deferral would not likely change the overall potential impacts to water quality within the planning area. However, it would substantially reduce the high potential impacts from a large oil spill to a moderate level for the coastline and embayment areas along this part of northern Florida.

Deferral of this area would avoid possible local impacts to nearshore shallow water communities and eliminate the low potential impacts to local deep-water areas. No change in regional impact levels is expected.

f. Deferral Recommended by

State of Florida; State of North Carolina; County of Volusia; Florida; National Aeronautics and Space Administration

South Atlantic Planning Area

Submarine transit lanes

a. Geographic Description

This candidate encompasses 1,138 blocks and covers an area of 6,478,843 acres (2,621,952 hectares). The submarine transit lanes within the South Atlantic Planning Area lie within deep waters southeast of North Carolina and South Carolina. They lie in water depths from approximately 200 to 2,000 m.

b. Sales (and date held) for which the Subarea was Studied and Disposition in Each Sale

Submarine transit lanes off the coasts of North Carolina, South Carolina, and Florida:

- Not studied as an alternative at the EIS stage
- Offered in Sales 43 (0 leases), 56 (10 leases), RS-2 (4 leases), and 78 (0 leases).

c. Oil and Gas Resource Potential

The deferral option contains structural and stratigraphic traps associated with the Jurassic/Cretaceous carbonate paleo-shelf edge trend.

Data coverage over most of the candidate is sufficient to define specific prospects, and the central parts of the subarea are thought to be prospective where they cut across the carbonate paleo-shelf edge and large anticlinal structures. Elsewhere, the subarea is not very prospective or is of unknown potential.

d. Description of the Environment

The transit lanes are primarily in deep water areas where the predominant communities consist of annelid species. Individual density within the area is highest on the upper slope at about 600 m. Density is lower at the 1,500-m isobath and then increases again at 2,000 m. Density then decreases sharply at the 3,000- and 3,500-m isobaths. The most landward section contains 100-m depths where high-relief live bottoms may be located, and which can support an abundance of encrusting corals, sponges, and associated live assemblages. The deeper live bottom areas on the shelf break have a lower incidence of large sponges and octocorals.

e. Potential Impacts Avoided by Deferral of this Subarea

No substantial change in impacts to water quality is anticipated.

Because of the water depth, sparsity of live bottoms, and shifting abundances of fish, the potential for impacts in this area is low. deferral of this area would reduce the low local impacts expected in the area.

f. Deferral Recommended by

State of North Carolina

South Atlantic Planning Area

Cape Canaveral Operating Area

a. Geographic Description

This candidate encompasses 356 blocks and covers and area of 2,026,774 acres (820,224 hectares). This area lies east of Cape Canaveral, Florida. It extends from the immediate coastline, out past the 79°W longitude line, approximately 70 to 80 miles from shore, in water as deep as 500 to 600 m.

b. Sales (and date held) for which the Subarea was Studied and Disposition in Each Sale

The Cape Canaveral Operating Area:

° Not studied as an alternative at the EIS stage
° Never leased

c. Oil and Gas Resource Potential

Except for a small part of a Triassic basin with associated stratigraphic traps, no other mapped structures occur in the subarea. A line of low relief structural traps lies on the seaward edge of the eastern boundary of the subarea.

Data coverage is sparse, and the area is thought to be not very prospective.

d. Description of the Environment

Contained within this area are shallow water and deep water banks of Oculina coral. The shallow water coral is common, small, stout, and found in water 1 to 30m deep. The deep water form is unique in that it grows in 46 to 154m of water, grows 9 to 15m high and is highly fragile. Large populations of grouper and other fishes are found on the deep water coral banks. The western edge of the delineated area contains portions of calico scallop beds and the eastern edge contains royal red shrimp fishing grounds.

e. Potential Impacts Avoided by Deferral of this Subarea

This subarea deferral would remove some of the potential for onshore visual impacts to the Cape Canaveral area of Florida resulting from offshore drilling facilities. The risk of impacts to coastal recreation areas from platform spills would also be slightly reduced.

No substantial change in impacts to water quality is anticipated.

Deferral of this area would eliminate possible impacts on the only known Oculina bank in the south Atlantic, and slightly reduce the potential impacts to the calico scallops and royal red shrimp.

f. Deferral Recommended by

National Aeronautics Space Administration

South Atlantic Planning Area

All Blocks Lying in Water Deeper than 3,000 meters (South Atlantic)

a. Geographic Description

This candidate encompasses 6,290 blocks and covers an area of 35,810,127 acres (14,492,160 hectares). These blocks lie in the far eastern portion of the planning area where water depths may be greater than 5,000 m. They lie as close to shore as 150 statute miles east of Cape Lookout and as far as 440 miles east of Charleston, South Carolina.

b. Sales (and date held) for which the Subarea was Studied and Disposition In Each Sale

Blocks in water depths greater than 3,000 meters, south Atlantic:

- Not studied as an alternative at the EIS stage
- Not offered

c. Oil and Gas Resource Potential

Structural and stratigraphic traps associated with the Jurassic/Cretaceous paleo-shelf edge trend occur within the subarea in the northern part above 33°N. Latitude.

Data coverage over the subarea is mostly sparse to non-existent and restricted to USGS seismic lines.

The northernmost parts of this option are thought to be prospective where they include segments of the carbonate paleo-shelf edge. Oil and gas potential is unknown in the remainder of the subarea.

d. Description of the Environment

The area is deep and the waters are cold (<3.5° C). The benthic faunal communities which have been sampled have demonstrated low total diversity and density. The primary faunal constituents are polychaetes, echinoderms, brotulid fish, and the macrourid fish *Coryphaenoides armatus*.

e. Potential Impacts Avoided by Deferral of this Subarea

No substantial change in impacts to water quality is anticipated. Deferral of this area would avoid the almost negligible potential impacts in the area. Impacts to the benthic communities, the most likely faunal constituent to experience any impact, would be eliminated.

f. Deferral Recommended by

Chevron

Eastern Planning Area - Gulf of Mexico

Miami Map Area

a. Geographic Description (if not defined in a sale document listed below):

The Miami map area consists of approximately 1,072,025 acres about 9 miles west of Collier and Monroe counties in Florida and extending a maximum distance of about 53 miles from the coast. Water depths range from 4 to 20 meters. This area extends south from the territorial sea at approximately 81°53"W longitude to 25°N latitude thence east to approximately 81°11"W longitude thence northwest along the territorial sea to the point of origin.

b. Sales (and date held) for which the Subarea was Studied and Disposition in Each Sale:

The Miami map area has never been included in the Eastern Planning Area and, therefore, has not been offered for lease.

c. Oil and Gas Resource Potential:

(1) Location of structures, prospects, and stratigraphic traps: Regional seismic data exist and a regional reconnaissance map was constructed some time ago from poor quality data. Only regional structural trends are shown and no prospects or stratigraphic traps are defined.

(2) Data coverage: Regional seismic data of questionable quality.

(3) Possible exploration/discovery trends within or adjacent to the area: This area lies within the eastern half of the South Florida Basin which contains producing fields onshore on the Florida Peninsula. This area lies about 40 miles, and possibly down dip, from the producing fields which are Lower Cretaceous in age.

(4) The resource potential for the area is rated moderate for oil and low for gas.

d. Description of the Environment:

The Miami lease area is located in water depths of less than 20 meters. Live bottom communities consisting of algae, ascidians, hard corals, gorgonians, hydrozoans, and sponges, can be expected, scattered throughout this area.

The Miami lease area is offshore of the Everglades National Park, extensive stands of mangroves, and freshwater marsh. Located south of the Miami lease area are Florida Bay and the Florida Keys. This entire coastal area is a sensitive and valuable national resource. The subarea lies in proximity to vast amounts of seagrass beds, mangroves, and marshes. The coastal and offshore area supports a number of coastal/marine birds and endangered species including the manatee, key deer, and numerous sea turtle nesting areas.

e. Potential Impacts Avoided by Deferral of this Subarea:

The deferral of this subarea would protect sensitive offshore live bottom areas from impacts from oil and gas activities. Discharges and anchoring from drilling operations would not impact the live bottom communities of the Miami lease area. Oil spills would not occur in this area from Minerals Management Service (MMS) permitted activities. Impacts to the coastal areas from oil spills occurring outside of the Miami lease area would be mitigated by the deferral of the subarea, since the time involved in the spill reaching land would be increased allowing for cleanup response, dispersion, and weathering of the oil. Deferral of this subarea may prevent significant impact to coastal habitats (seagrasses, mangroves, and marshes) and endangered species and coastal/marine birds.

f. Deferral Recommended by:

State of Florida

Eastern Planning Area - Gulf of Mexico

South of Latitude 25°N and East of Longitude 82°W

a. Geographic Description (if not defined in a sale document listed below):

This Eastern Gulf deletion candidate ranges from south of latitude 25°N to latitude 24°N and east of longitude 82°W. This area consists of approximately 115,000 acres lying offshore Monroe County. It extends southwestward from 23 miles off the coast of Florida to approximately 49 miles offshore in water depths ranging between 10-20 meters.

b. Sales (and date held) for which the Subarea was Studied and Disposition in Each Sale:

The area south of latitude 25°N and east of longitude 82°W has never been included in the Eastern Planning Area and, therefore, has not been offered for lease.

c. Oil and Gas Resource Potential:

(1) A regional reconnaissance structure map was constructed some years ago using available, but poor quality, seismic data. Only generalized regional structures are shown. No prospects or stratigraphic traps have been defined.

(2) There is dated regional seismic coverage.

(3) This area lies near the southern edge of the South Florida basin about 80 miles southeast of producing fields. A small amount of oil was discovered years ago near the Marquesas Keys, west of Key West about 20 miles south of the area. The potential horizon would be Cretaceous.

(4) The resource potential for the area is moderate for oil and low for gas.

d. Description of the Environment:

This subarea is located offshore the Florida Keys in water depths less than 20 meters. The offshore habitat is the same as that discussed for the larger Miami map area deferral of which this deferral area is a subset. South of this subarea lies the ecosystem associated with Florida Keys.

e. Potential Impacts Avoided by Deferral of this Subarea:

The deferral of this small subarea would protect live bottom communities from impacts due to oil and gas activities. Oil spills due to MMS permitted activities would not occur in this area. Although the potential for oil spills is low, the potential impact is significant. Deferral of this subarea would eliminate the potential for oil and gas leasing activity caused oil spills from occurring in the subarea, and would mitigate the impacts from spills which could occur outside the area by allowing increased time before contact for cleanup, dispersion, and weathering of the oil. Significant impacts to sensitive and valuable coastal habitats, coastal/marine birds, and endangered species may be avoided by deletion of this subarea.

f. Deferral Recommended by:

State of Florida

Eastern Planning Area - Gulf of Mexico

Those Areas Deferred From Sale 79

a. Geographic Description (if not defined in a sale document listed below):

The areas deferred from Sale 79 in the Eastern Gulf of Mexico include the 20-30 mile buffer zone and the Florida Middle Ground. They consist of approximately 8.59 million acres lying offshore Bay to Monroe Counties. This area extends eastward from the longitude 86°W to longitude 82°W and from latitude 30°N to latitude 25°N. The buffer zone extends up to 30 miles offshore while the Florida Middle Ground is located up to 86 miles offshore Florida. Water depths range from 20-60 meters for the buffer zone and 40 meters for the Middle Ground.

b. Sales (and date held) for which the Subarea was Studied and Disposition in Each Sale:

The areas were again deferred from Sale 94.

c. Oil and Gas Resource Potential:

(1) Structures have been identified within the subareas, but prospects and stratigraphic traps have not been identified.

(2) The area is covered by a regional seismic survey, and regional maps have been constructed from this data. However, for most of the B(g) zone south of latitude 26°N, there is no in-house data.

(3) Exploration trends within the zone are most likely Cretaceous.

(4) The entire area has a low potential for gas resources. The northern half has a low potential for oil, and the southern has a moderate potential.

d. Description of the Environment:

This deferral is a combination of the deferral areas of the Florida Middle Ground and the 30-mile buffer zone. The descriptions of the environment may be found in the discussions of those subareas.

e. Potential Impacts Avoided by Deferral of this Subarea:

See Subareas descriptions for Thirty Mile Buffer Zone and Florida Middle Ground subareas.

f. Deferral Recommended by:

State of Florida, Tampa Bay Regional Planning Council, National Resource Defense Council.

Thirty-Mile Buffer Zone Offshore Panama City to Naples, Florida, and South of Naples to the 20-Meter Isobath

a. Geographic Description (if not defined in a sale document listed below):

The 30-mile buffer zone in the Eastern Gulf of Mexico consists of approximately 8.46 million acres lying offshore Bay to Monroe Counties. This area extends eastward from the longitude 86°W to longitude 82°W and latitude 30°N to latitude 25°N. The area is in water depths up to about 60 meters.

b. Sales (and date held) for which the Subarea was Studied and Disposition in Each Sale:

Sale 79 (January 1984) - This subarea was not discussed in the EIS as a deletion alternative or deferral area, but it was deferred from the sale.

Sale 94 (November 1985) - This subarea was deferred from the proposed action in the Environmental Impact Statement (EIS) and was deferred from the sale.

c. Oil and Gas Resource Potential:

See Discussion Under Subareas Deferred from Sale 79.

d. Description of the Environment:

The offshore area is scattered with live bottom communities comprised of sponges, octocorals, gorgonians, and a few hard corals. The actual extent and location of these live bottoms is unknown. The area included in the offshore seagrass beds deferral area is wholly within the 30-mile buffer zone deferral.

The coastal area of Florida encompasses a wide variety of habitats, including seagrass beds, salt marshes, fresh marshes, mangroves, barrier beaches, estuaries, and coral reefs. The estuaries and marshes are very important in the production of commercially and recreationally important fish and wildlife species. The Florida beaches are important storm protection and erosion control areas. The Florida tourism industry is based on the presence of these beaches. The seagrass beds support numerous commercially and recreationally important fishery and wildlife species.

e. Impacts Avoided by Deferral of this Subarea:

Deferral would preclude drilling operations and so eliminate the threat of damage from oil spills, drilling discharges, anchoring, or platform emplacement in the areas removed.

In addition, the deferral candidate would provide a buffer zone for potential oil spills which would allow additional time for spill cleanup, containment or dispersion, and weathering before contact with the shore and sensitive coastal habitats.

f. Deferral Recommended by:

State of Florida

Fifty-Mile Buffer Zone Off Florida

a. Geographic Description (if not defined in a sale document listed below):

The 50-mile buffer zone in the Eastern Gulf of Mexico includes approximately 30 percent of the Eastern Planning Area (23 million acres) lying offshore Escambia to Monroe Counties. It extends westward from longitude 82°W to longitude 87°W and south from latitude 30°N to latitude 24°N. Water depths range up to 600 meters.

b. Sales (and date held) for which the Subarea was Studied and Disposition in Each Sale:

Because the area south of latitude 25°N has never been included in the Eastern Planning Area, that portion of the 50-mile buffer alternative which surrounds the Florida Keys and Dry Tortugas has not been offered for lease. Areas north of 25°N latitude such as the seagrass beds, and the area within 30 miles of the coast have been deferred from earlier sales. Areas within the 50-mile buffer have also been offered and active leases exist.

c. Oil and Gas Resource Potential:

(1) Numerous structures have been identified within the Buffer Zone but no prospects or stratigraphic traps have been identified.

(2) The 50-mile buffer zone is covered by a regional seismic survey. Locally denser grids are available. Wells have been drilled in the Destin Dome area and fields exist in the Florida Panhandle to the north. Several wells have been drilled offshore west of Tampa.

(3) Potential exploration trends in the Destin Dome area are in the Upper Jurassic. The rest of the arch to the south lies within a probable Cretaceous trend.

(4) The area in the north has a high to moderate potential for gas and a moderate potential for oil. The area in the south has a moderate oil potential and a low gas potential.

d. Description of the Environment:

This subarea includes the entire area discussed in the 30-mile buffer zone deferral and extends this area an additional 20 miles offshore.

A major addition to the other deferral areas considered is a 50-mile buffer extending around the Florida Keys and Dry Tortugas. This portion of the subarea surrounds an extremely sensitive and valuable resource. The habitats of this area include the coral reefs, mangroves, and seagrass beds. Numerous coastal/marine birds and rare and endangered species inhabit this area.

Coral reefs are highly complex and diverse communities. Many important fisheries are directly tied to the coral reef. Coral reefs also support a significant portion of the tourist industry of Florida. Coral reefs are located in State waters surrounded by the deletion alternative, and also within Federal OCS waters between Key West and the Dry Tortugas.

The mangrove community is composed of four species: the red, black, and white mangroves, and buttonwood. The community is zoned generally from the red mangroves in the submerged land at the water's edge, through the intertidal zone inhabited by black mangrove, to buttonwood and white mangroves on higher ground. Mangroves produce large amounts of detrital material which is contributed to the surrounding ecosystem. Numerous small fish and invertebrates use the mangrove environment, especially the prop roots of the red mangroves, for feeding and refuge. Birds such as herons and spoonbills use the mangrove islands as rookeries due to their relatively inaccessible nature and proximity to feeding areas. Mangroves serve as shoreline erosion protection and as substrate builder by trapping and stabilizing intertidal sediments and debris.

Seagrasses in the area are discussed in several other deferral areas which are part of this larger deferral area.

Coastal birds of the area include, herons, egrets, ibis, spoonbills, ospreys, and pelicans. Rare species which inhabit this area include the federally endangered key deer and loggerhead turtles.

e. Impacts Avoided by Deferral of this Subarea:

The major potential impact producing factors that could affect sensitive offshore habitats in the Eastern Gulf of Mexico are mechanical damage due to anchors, drilling, pipelines, and platform emplacement, as well as smothering effects from drilling discharges. These impact producing factors, with the exception of pipeline emplacement, would be eliminated from the subarea. Elimination of these impact producing factors would preclude potentially high impacts to live bottom communities, coral reefs, and seagrasses; to the recreational and commercial fisheries of the area; and to the intrinsic biological, ecological, and aesthetic values of these areas.

Deferral of the subarea would preclude the impacts due to oil spills discussed in the 30-mile buffer zone subarea and add an additional buffer of approximately 20 additional miles to the coast. Potentially severe oil spill impacts resulting from a spill directly over coral reefs or seagrass beds would be avoided.

f. Deferral Recommended by:

Florida Department of Natural Resources

Eastern Planning Area - Gulf of Mexico

Florida Middle Ground

a. Geographic Description (if not defined in a sale document listed below):

The Florida Middle Ground in the Eastern Gulf of Mexico includes 23 blocks and approximately 132,000 acres lying offshore Franklin County. It extends south from latitude 29°N to latitude 28°N and west from longitude 84°W to longitude 85°W. The Middle Ground extends up to 86 miles offshore Florida in water depths up to 40 meters.

b. Sales (and date held) for which the Subarea was Studied and Disposition in Each Sale:

Sale 79 (January 1984) - The Florida Middle Ground was discussed in the EIS as a deletion alternative and was deferred from the sale.

Sale 94 (November 1985) - The Florida Middle Ground was deferred from the proposed action in the EIS.

c. Oil and Gas Resource Potential:

(1) Structures have been identified within the area but prospects and stratigraphic traps have not been identified.

(2) There is regional seismic coverage in the area.

(3) The potential exploration trend is in the Cretaceous.

(4) The Florida Middle Ground area has a low oil and gas potential.

d. Description of the Environment:

The Florida Middle Ground is probably the best known and most biologically developed of the live bottom areas with extensive inhabitation by hermatypic corals and related communities. This area is 87 nmi (160 km) west-northwest of Tampa and has been designated as a Habitat Area of Particular Concern (HAPC) by the Gulf of Mexico Fishery Management Council. The taking of any corals is prohibited except as authorized by permit.

The Florida Middle Ground represents the northernmost extent of coral reefs and their associated assemblages in the Eastern Gulf. The Middle Ground is like the Flower Garden Banks off Texas--typical Caribbean reefal communities although somewhat depauperate in terms of these types of coral communities.

Favorable environmental conditions associated with offshore distance and moderating currents allow occupation of the Middle Ground by numerous stenoecious fishes recruited from the Caribbean-West Indian region. Transparent waters, shallow reef crests, irregular bottom topography, well-defined currents, and carbonate sediments attract many insular reef fishes either rare or absent at other West Florida Shelf reefs. Environmental stability at the Middle Ground has undoubtedly enhanced development of its diverse fauna.

The dominant stony corals of the Middle Ground include Madracis decactis, Porites divaricata, Dichochocoenia stellaris, and Dichochocenia stokesii. Octocorals, a relatively minor component of other Gulf reefs, are prominent on the Middle Ground; dominant forms include Muricea elongata (orange Muricea), Muricea laxa (delicate Muricea), Eunicea calyculata (warty Eunicea, and Plexaura flexuosa (sea rod). Recreational activities are limited by the distance from shore. Despite the distance from the coast to the Florida Middle Ground, enthusiastic sport fishermen and recreational divers have been reported to frequent the area. The Middle Ground was nominated as a marine sanctuary. This area is frequented by commercial fishing boats since the primary fish species involved include the red snapper and grouper, which dominate the landings and value of landings of Gulf reef fish.

e. Impacts Avoided by Deferral of this Subarea:

This alternative would defer the 23 blocks containing "No Activity Zone" areas of the Florida Middle Ground. Deferring this small percentage of the Eastern Gulf offering will result in a very large reduction of the potential impact to the high value biological resources.

The biological resources of the Middle Ground are considered very sensitive to potential impacts due to oil and gas operations. Deferral would remove the risks to the biological resources of the area from offshore operations on the 23 blocks.

f. Deferral Recommended by:

Florida Department of Natural Resources

Eastern Planning Area - Gulf of Mexico

Offshore Seagrass Beds

a. Geographic Description (if not defined in a sale document listed below):

This Eastern Gulf deletion candidate ranges south from latitude 30°N to latitude 28°N and west from longitude 82°W to longitude 84°W. This area consists of approximately 1.07 million acres lying offshore from Wakulla to Pasco Counties. It extends southeastward from 9 miles off the coast of Florida to approximately 25 miles offshore in water depths up to 10 meters.

b. Sales (and date held) for which the Subarea was Studied and Disposition in Each Sale:

Sale 79 (January 1984) - The seagrass beds were discussed as a deletion alternative in the EIS and were deferred from the sale.

Sale 94 (November 1985) - The seagrass beds were deferred from the proposed action in March 1984 after being included in the moratorium.

The boundaries of this subarea have varied between the different deletion alternatives and deferrals.

c. Oil and Gas Resource Potential:

(1) No structures have been identified in this area.

(2) Some regional seismic coverage exists.

(3) Any exploration possibilities are probably in the Cretaceous.

(4) The area has a low oil and gas resource potential.

d. Description of the Environment:

Extensive seagrass beds inhabit the Florida Big Bend offshore area. These seagrasses are comprised predominantly of Thalassia testudinum, Syringodium filiforme, and Halophila spp. The actual extent of the seagrass beds is unknown at present; however, an MMS funded study is nearing completion which would help define the extent of these seagrass beds. These seagrass beds are important to the overall ecology of the Eastern Gulf of Mexico, and support numerous commercially and recreationally important fishery and wildlife species.

The coastal area surrounding the subarea is densely vegetated with salt marsh. This coastal area is important to the fish and wildlife species of the area.

e. Potential Impacts Avoided by Deferral of this Subarea:

Deferral of this subarea would preclude impacts to the seagrass areas from oil and gas drilling operations. Discharge of drill muds and cuttings directly on the seagrasses, causing smothering and potential long-term denuding of the area surrounding the drilling activity would be avoided. Direct physical impact of rig emplacement and anchoring of supply boats would also be avoided. Deferral of the subarea would also preclude oil spills from originating in the area, thereby providing a buffer between oil spill source and sensitive coastal marshes of the Florida Big Bend. Thus, deferring this small percentage of the Eastern Gulf offering would result in a very large reduction of the potential impact to these high value biological resources. Only oil spills from outside the seagrass area would still pose a threat to this area. Deferral of this subarea would remove nearly all the risk to offshore seagrass beds from oil and gas activities, since the oil spill model indicates that there is a very small probability that an oil spill will occur and impact this area.

f. Deferral Recommended by:

South Florida Regional Planning Council

Eastern Planning Area - Gulf of Mexico

Areas with Coral Reefs

a. Geographical Description (if not defined in a sale document listed below):

This Eastern Gulf deletion candidate combines the 50-mile buffer zone and the Florida Middle Ground for a total of 23.1 million acres. The area ranges from 9-86 miles offshore in water depths up to 600 meters and extends from Escambia to Monroe Counties.

b. Sales (and date held) for which the Subarea was Studied and Disposition in Each Sale:

The areas with coral reefs south of latitude 25°N have never been offered for lease since this area has never been included in the Eastern Planning Area.

c. Oil and Gas Resource Potential:

See discussion for the subarea involving the Florida Middle Ground and the 50-mile buffer zone.

d. Description of the Environment:

See discussion for the subarea involving the Florida Middle Ground and the 50-mile buffer zone.

e. Potential Impacts Avoided by Deferral of this Subarea:

See subarea description for the Fifty Mile Buffer Zone and Florida Middle Ground subareas.

f. Deferral Recommended by:

South Florida Regional Planning Council

South of Latitude 26°N

a. Geographic Description (if not defined in a sale document listed below):

The area south of latitude 26°N ranges from that latitude to latitude 24°N and east from longitude 85°W to longitude 81°W. The area consists of approximately 19.1 million acres in the Eastern Gulf of Mexico and extends southwestward from 9-308 miles offshore in water depths ranging between 10-3,200 meters.

b. Sales (and date held) for which the Subarea was Studied and Disposition in Each Sale:

The area south of latitude 25°N has not been included in the Eastern Planning Area and, therefore, has never been offered for lease. The portion of the subarea between latitude 26°N and latitude 25°N is discussed below.

Sale 79 (January 1984) - The area between latitude 26°N and latitude 25°N was discussed in the EIS as a deletion alternative. This area was not deferred from the sale.

Sale 94 (November 1985) - The area between latitude 26°N and latitude 25°N was discussed as a deletion alternative.

c. Oil and Gas Resource Potential:

(1) No structures, prospects, or stratigraphic traps have been identified within this area.

(2) There is limited regional seismic coverage.

(3) Possible exploration targets would be the Cretaceous, possibly the Jurassic.

(4) The area has a moderate oil potential and a low gas potential.

d. Description of the Environment:

The area south of latitude 26°N includes the Miami lease area (subarea 1), the area south of latitude 25°N and east of longitude 82°W (subarea 2), and that portion of the 50-mile buffer (subarea 5), surrounding and between the Florida Keys and Dry Tortugas and along the coast south of latitude 26°N.

e. Impacts Avoided by Deferral of this Subarea:

Adoption of this deferral would ensure that significant live bottom communities, seagrass beds, and coral reefs would be protected from physical disturbance associated with oil and gas operations, such as those caused by anchor and drilling vessel placement, and smothering from drilling cuttings discharges. Adoption would also ensure that an oil spill would not occur on these blocks. The coastal areas described in subareas 1 and 2, and the Florida Keys/Dry Tortugas described as a portion of subarea 5, would be buffered from potential spills occurring outside of the subarea.

f. Deferral Recommended by:

South Florida Regional Planning Council

Western and Central Planning Areas Gulf of Mexico

8(g) Blocks

a. Geographic Description (if not defined in a sale document listed below):

The 8(g) blocks range from longitude 97°W to longitude 87°W and latitude 26°N to latitude 30°N which includes all three planning areas. The are consists of approximately 1.9 million acres in the Central and Western Planning Areas and 365,942.64 acres in the Eastern Gulf of Mexico. The 8(g) zone extends 3 miles off the 3-mile State/Federal boundary, except off the Texas coast where it extends 3 miles off the 3-league line. Water depths in these zones range from 0-400 meters.

b. Sales (and date held) for which the Subarea was Studied and Disposition in Each Sale:

The 8(g) blocks have never been discussed as a deletion alternative in an EIS and have never been deferred from a sale. While few such blocks have been offered in the Eastern Planning Area, most of the Central and Western planning area blocks within 3 miles of the State/Federal boundary are already under lease.

c. Oil and Gas Resource Potential:

(1) Structures have been identified throughout the 8(g) zone. Prospects and stratigraphic traps are not identified.

(2) There is extensive seismic coverage, and many wells have been drilled in and near the zone.

(3) The 8(g) zone extends from the Rio Grande River in Texas, to the Florida/Alabama line. Most of this lies within the Miocene producing trend. A part of South Padre Island, most of North Padre Island, all of Mustang Island, and a small part of Matagorda Island fall within the Oligocene trend. The rest of the zone around to the northern part of the Chandeleur Area lies within the Miocene trend. The very northern end of the Chandeleur Area and the Mobile Area lie within the Jurassic producing trend.

(4) Most of area is considered to have a high gas resource potential. Most of the region, has a high oil potential.

d. Description of the Environment:

The 8(g) blocks adjacent to State waters are obviously located in the shallowest portions of the OCS. These areas, because of their proximity to shore, area important recreational as well as commercial fishing areas. Shrimp and bottom fish are important fisheries of the area. Platforms within this subarea attract fish and, therefore, are used extensively by fishermen.

e. Impacts Avoided by Deferral of this Subarea:

Platforms and rigs remove a portion of the OCS from the available trawlable area. Deferral of this subarea would preclude further drilling and platforms within additional leased blocks in the subarea. Oil spills would not occur within the subarea from proposed lease activities. Should an oil spill occur outside of the subarea, the subarea would provide a 3-mile buffer between the Federal and State waters so that oil spill impacts to coastal areas would be slightly mitigated.

f. Deferral Recommended by:

Governor of Texas

All Planning Areas Gulf of Mexico

Water Depths Greater than 3,000 Meters

a. Geographic Description (if not defined in a sale document listed below):

This deletion candidate ranges from longitude 95°-93°W and latitude 26°N in the Western Gulf; longitude 91°-87°W and latitude 26°N in the Central Gulf; and from longitude 87°-84°W and latitude 28°-24°N in the Eastern Gulf of Mexico. The area consists of 664,820 acres, 2.5 million acres, and 14.5 million acres, respectively. It extends south from 144-277 miles offshore in water depths of 3,000 meters and greater.

b. Sales (and date held) for which the Subarea was Studied and Dispositon in Each Sale:

Similar deferral alternatives have been considered for recent sales but at differing water depths.

Sale 72 (May 1983), Sale 74 (August 1983), and Sale 79 (January 1984) - A deletion alternative for areas in water depths greater than 1,000 meters was discussed in the EIS. The area was not deferred in these sales.

Sale 98 (May 1985)and Sale 102 (August 1985) - Although not discussed in the EIS, the area in water depths greater than 2,400 meters was deferred from these sales.

c. Oil and Gas Resource Potential:

(1) Large regional structures have been mapped for reconnaissance seismic data in the area lying between longitude 93°W and longitude 95°W. No structures have been determined for the rest of the area below 3,000 meters.

(2) There are only a few regional seismic lines available.

(3) Although little information is available, the area between longitude 93°W and longitude 95°W lies just south of the Sigsbee escarpment. It is possible that both Tertiary and Cretaceous sediments occur there as possible targets. Sediments in the area between longitude 85°N and longitude 91°N range from Jurassic to Pleistocene in age. The northern part of the area north of latitude 26°N lies within a part of the Mississippi Fan, which is known to contain sand sequences that could be potential reservoir beds.

(4) The area has a low resource potential for oil and gas.

d. Description of the Environment:

The biology of the deep water environment is not well known. The deep water Gulf benthic communities exhibit depth-related zonation. At about 3,200 meters the zonation boundaries become indistinct, if present at all, probably because gradients of the physical parameters level off from this depth on as compared to the slope. The megafauna associated with these water depths is depauperate; however, the zone contains benthic species which do not occur elsewhere. Recently, deepwater vent associated communities have been discovered in the Gulf. The extent of these communities is not known. Their occurrence below 3,000 meters is possible.

e. Impacts Avoided by Deferral of this Subarea:

Adoption of this deferral option would serve to prevent adverse physical effects on deepwater biological communities. No drilling or production-related oil spills would occur on those blocks. The probability of an oil spill occurring is already very low, so the adoption of this deferral would not significantly affect overall oil spill probabilities. Because the more sensitive resources are located in water depths shallower than 3,000 meters, this deferral would not reduce the anticipated overall level of affect on the area's resources.

f. Deferral Recommended by:

Chevron

Central California Planning Area

Point Reyes Wilderness Area

a. Geographic description: The Point Reyes Wilderness Area is an onshore area which extends from the mouth of Tomales Bay to the Point Reyes Bird Observatory. The Outer Continental Shelf Lands Act Amendments of 1978 prohibits any OCS oil and gas exploration or development within 15 miles of the boundaries of the wilderness area unless the State of California allows oil and gas activities on lands in State waters. Thus, this subarea deferral includes approximately 92 blocks (500,000 acres) located within 15 miles of the wilderness area. A portion of the Point Reyes/Farallon Islands National Marine Sanctuary subarea is included in this deferral.

b. Description of the environment: The shoreline of the wilderness area contains unaltered rocky shores and sandy beaches which maintain rich intertidal communities, serve as breeding and haulout areas for marine mammals, and as nesting area for seabirds.

c. Potential impacts avoided by deferral of this subarea: Impacts to intertidal communities on the Point Reyes Wilderness Area would be reduced due to the elimination of potential platforms and associated development activities. Similarly, the risk of potential platform spills originating from within this area would be eliminated. This would provide additional protection for the intertidal communities, marine mammal haulout areas, and seabird nesting areas.

d. Resource potential: In terms of the quantity and quality, the geotechnical data available in the proposed deletion area area sufficient to define specific traps throughout the entire area but, to date, no structural traps have been identified.

Stratigraphic traps may be present throughout the area.

Possible exploration/discovery trends within or adjacent to the subarea, including the San Andreas Fault Zone and the Drakes Bay-Bolinas Trend, extend northwestward across the northeast part of the area. The Farallon-Pigeon Point High trends northwestward along the southern border of the area.

e. Deferral recommended by: Leasing prohibited by OCS Lands Act.

Cordell Bank

a. Geographic description: Cordell Bank is a large seamount lying 50 miles northwest of San Francisco and approximately 30 miles north of the Farallon Islands. The center of the bank is near 38° 01' north latitude, 123° 25' west longitude. This subarea includes parts of 4 blocks, approximately 22,700 acres using the 91 meter contour.

b. Description of the environment: Cordell Bank is roughly elliptical and is 9.5 by 4.5 miles at the 91 meter depth contour. Overall the area is relatively flat at depths of 180 to 210 ft. (55 to 63 meters), but is interrupted by steep pinnacles. There are at least four ridges within diving depths of 120 to 140 ft. (37 to 43 meters) although the shallowest depth is 114 ft. (35 meters). The biological community on Cordell Banks is described as "exceptionally lush and healthy, consisting of algae, invertebrates, fish, birds and mammals" (Schnieder, 1982). Schnieder states: "The list of species which have been collected at Cordell Bank include many of the common organisms such as the strawberry anemone Corynactis californica and some uncommon or rate species such as the hydrocoral Allopora californica and the diatom Entopyla cf. E. incurvata and the gastropod Pedicularia californica, and several new taxa, including at least two new genera of algae and a possible new species of the scallop Chylamys. It is very likely that many undescribed organisms exist at Cordell Bank and will be found in future studies."

c. Potential impacts avoided by deferral of this subarea: Deferral of this subarea will reduce impacts to water quality in the area since no platform will occur. The water quality of the area is unaltered and pristine with respect to anthropogenic influences. The principal impacts that would be avoided by this deferral would be to eliminate the possibility of adverse effects to the productive hard bottom benthic community and the hydrocoral Allopora californica.

d. Resource potential: In terms of quantity and quality, the geotechnical data available in the proposed deletion area are sufficient to define specific traps throughout the entire area but, to date, no structural traps have been identified in the mapped area.

Stratigraphic traps may be present around the border of the area.

Possible exploration/discovery trends within or adjacent to the subarea include the Farallon-Pigeon Point High which extends southeastward from Cordell Banks.

Central California Planning Area

Point Reyes/Farallon Islands National Marine Sanctuary Geographic Description

a. Geographic description: The boundaries of the marine sanctuary are officially defined as follows:

"The sanctuary consists of an area of the waters adjacent to the coast of California north and south of the Point Reyes Headlands, between Bodega Head and Rocky Point and the Farallon Islands (including Noonday Rock), and includes approximately 948 square nautical miles.

"The Shoreward boundary follows the mean high tide line and the seaward limit of Point Reyes National Seashore. Between Bodega Head and Point Reyes Headlands, the sanctuary extends seaward 3 nm beyond State waters. The sanctuary also includes the waters within 12 nm of the Farallon Islands, and between the Islands and the mainland from Point Reyes Headlands to Rocky Point. The sanctuary includes Bodega Bay, but not Bodega Harbor.

Portions of the San Francisco Bay and Point Reyes Wilderness Area deferrals are included within this subarea.

b. Description of the environment: The shorelines consist of rocky shores and sandy beaches which maintain rich intertidal communities. The sanctuary contains the largest breeding colony of seabirds in California and is an important pinniped rookery. The waters of the area are highly productive and are important foraging area for the bird and pinnipeds.

c. Potential impacts avoided by deferral of this subarea: Deferral of this Subarea would reduce a variety of potential environmental effects. First, the potential of an oil spill affecting the island: would be reduced thereby protecting the habitats of seabirds, pinnipeds, and other marine dependent life. Even if an oil spill from another area drifted into the area there would be time more for weathering; and the spill would be less toxic. Second, the lack of exploration and development activity would eliminate the possibility of adverse effects of normal and oil and gas operations on biological communities, as well as social and cultural environments.

d. Resource potential: In terms of quantity and quality, the geotechnical data available in the proposed deletion area are sufficient to define specific traps throughout the area except the southwestern 1/4, where data are not sufficient to define zones of hydrocarbon potential. No structural traps have been identified in the area.

Stratigraphic traps may be present in the northeastern 1/2 and the southwestern 1/4 of the area.

Possible exploration/discovery trends within or adjacent to the subarea include the San Andreas Fault Zone and the Drakes Bay-Bolinas trend which extends northewestward across the northeast part of the area and the Farallon-Pigeon Point high which trends northwestward across the central part of the area.

e. Deferral recommend by: California Senate, California Coastal Commission, The Whale Center, Monterey County, California Department of Justice.

Central California Planning Area

San Francisco Bay Precautionary Area

a. Geographic description: This area represents a portion of the San Francisco Bay Vessel Traffic Precautionary Area and an adjacent area totalling 16 whole and partial blocks. The area is just south of the entrance to San Francisco Bay offshore the San Francisco/San Mateo County line, and bounded to the north and west by the Farallon Islands-Pt. Reyes National Marine Sanctuary and to the east by the 3-mile State jurisdiction line. It has been the policy of the U.S. Coast Guard to not allow structures in established precautionary areas.

b. Description of the environment: The San Francisco Bay Precautionary Area is part of the marine vessel routing system controlled by the U.S. Coast Guard and the International Maritime Organization. This area is directly adjacent to the entrance to San Francisco Bay, one of the busiest ports in the nation, and includes access to the Ports of San Francisco, Oakland, Richmond, and Sacramento. For calendar year 1982 the San Francisco Harbor had a total of 9,640 inbound vessel trips (U.S. Army Corps of Engineers, 1984).

c. Potential impacts avoided by deferral of this subarea: Deferral of this subarea would reduce or eliminate potential adverse effects on vessel traffic, recreation and tourism, and aesthetics. In addition, protection of biological, social, and cultural environments would be enhanced.

d. Resource potential: In terms of quantity and quality, the geotechnical data available in the proposed deferral area are sufficient to define specific traps in all parts of the area except the northeast 15% of the area in which data is sufficient to define specific plays only. Structural traps have been identified throughout the mapped area.

Stratigraphic traps may be present throughout the area.

Possible exploration/discovery trends within or adjacent to the subarea include the San Andreas Fault Zone which extends across the northeastern edge of the area. The Drakes Bay-Bolinas trend extends across the area. Oil sands are exposed onshore east of the area.

e. Deferral recommend by: State of California, Santa Barbara County, Port of Long Beach, California Department of Justice, Monterey County.

Central California Planning Area

Monterey Bay

a. Geographic description: Two distinct deferral areas are proposed for the Monterey Bat subarea. The first involves a 10 mile buffer zone which parallels the coastline from a point 6 miles north of Santa Cruz south to Malpaso Creek. This buffer consists of 28 blocks and approximately 159,000 acres and is similar to a buffer proposed in the Big Sur subarea. The second proposed Monterey Bay subarea deferral includes that area west of the 10 mile buffer enclosed by a southwest line that extends from a point 6 miles north of Santa Cruz to a point which is 48 miles offshore due west of Malpaso Creek. This deferral includes 67 blocks and approximately 381,000 acres. Industry interest in this second proposed deferral area is currently considered low.

b. Description of the environment: The important biological areas contained in this deferral area include the subtidal Monterey Canyon in Monterey Bay with its included hydrocoral Allopora californica. Intertidally, the rocky areas that are thought to be possibly unique include Pacific Grove Marine Gardens ASBS, Cypress Point and Point Pinos, and the area from Carmel River to Point Lobos. The important estuary adjacent to the deferral area is Elkhorn Slough.

The greatest public concern in this area has been expressed for the sea otter whose range occurs within this deferral area.

c. Potential impacts avoided by deferral of this subarea: Deferral of the area would reduce potential visual effects and provide protection for a significant number of Monterey Bay resources by ensuring additional time for weathering, diversion and cleanup of an exploration or development related oil spill in the event such a spill should occur. Specific resources provided protection are mentioned above and include: 1) Intertidal Benthos- rocky intertidal areas of Pacific Grove, Cyprus Point, Point Pinos, Carmel River to the Point Lobos area; 2) Subtidal Benthos, including the Monterey Canyon; 3) the important estuary, Elkhorn Slough; and 4) the California sea otter habitat.

Deferring the larger area offshore Monterey Bay along with the larger area in the Big Sur subarea would reduce the size of the Central California Planning Area by important approximately one-third.

d. Deferral recommended by: County of Monterey, California 5th District Supervisor.

Central California Planning Area

Big Sur Area

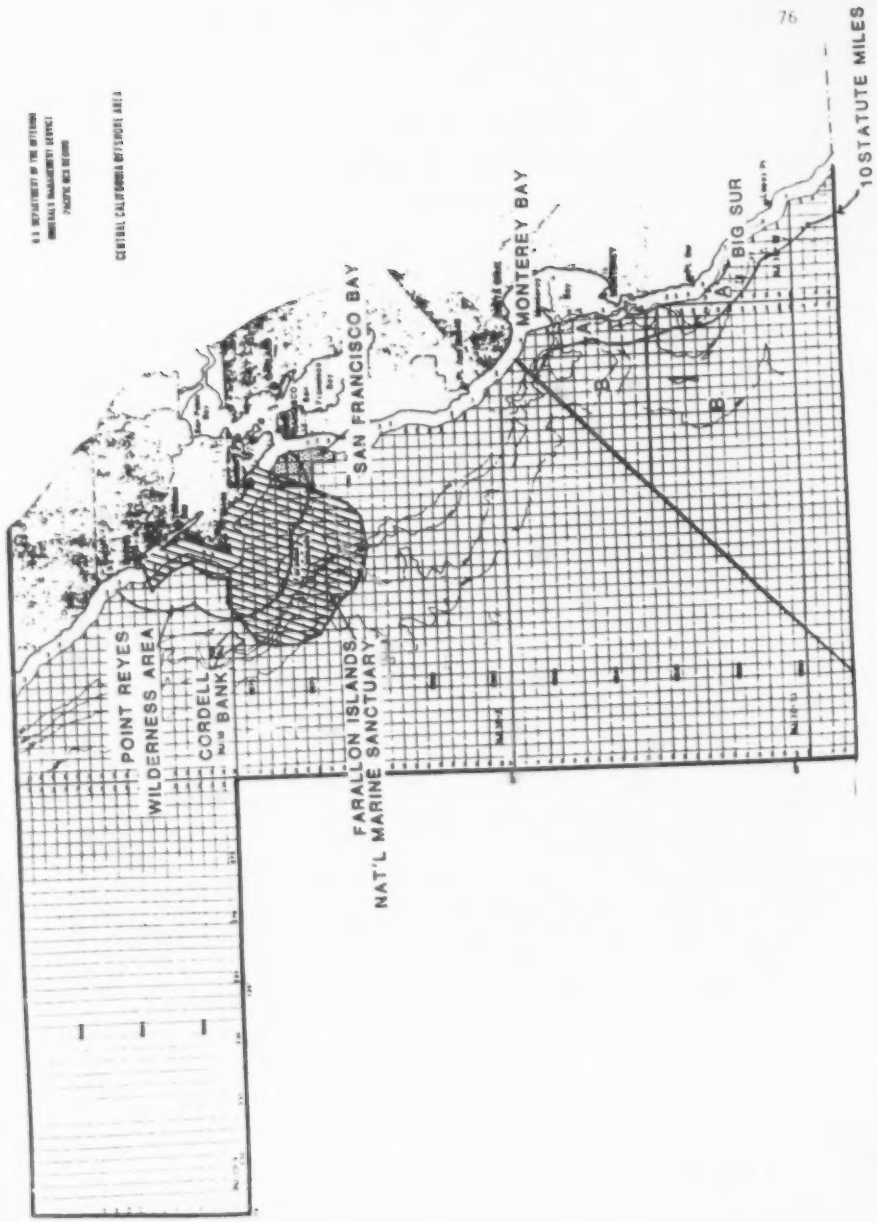
a. Geographic description: Two deferrals are proposed for the Big Sur subarea. The first involves a 10 mile buffer zone which parallels the coastline from Malpaso Creek south to the Monterey - San Luis Obispo County border. This buffer consists of approximately 49 blocks and 278,000 acres and is similar to a buffer proposed in the Monterey Bay subarea. The second deferral proposed for the Big Sur subarea includes that area west of the 10 mile buffer zone with a northern boundary which extends from the 10 mile line west to a point 48 miles offshore Malpaso Creek. The western boundary of the deferral area extends southwest to a point 131 miles offshore the Monterey - San Luis Obispo County border. This proposed deferral includes approximately 400 blocks and approximately 2.3 million acres. Industry interest in the second deferral area is currently considered low.

b. Description of the environment: The subarea includes the California sea otter population and range from the Monterey - San Luis Obispo county line north to Malpaso Creek. In addition to the sea otter, thousands of seabirds, including the brown pelican, and gray whales use this section of the coast seasonally. Over one million visitors a year (Sale 53 FEIS) visit this subarea and adjacent coastline, attracted to the many scenic areas and cultural attractions such as Hearst's Castle and various State parks and reserves.

c. Potential impacts avoided by deferral of this subarea: Deferral of these areas would reduce potential visual effects and provide protection for a significant number of resources by ensuring additional time for weathering, diversion, and cleanup of an exploration or development related oil spill should such a spill occur. Potential effects of normal operations on air or water quality as well as social, biological and cultural environments would also be reduced or eliminated.

Deferral of the larger area in the Big Sur subarea along with the larger area offshore Monterey Bay would reduce the size of the Central California Planning Area by approximately one-third.

d. Deferral recommended by: County of Monterey, California 5th District Supervisor.



Santa Barbara Ecological Preserve and Buffer Zone

a. Geographic description: The Santa Barbara Channel Ecological Preserve and Buffer Zone is locates south of the city of Santa Barbara. The preserve was established March 21, 1969 by Public Land Order 4587. The Preserve consists of ten full and partial tracts "withdrawn from all forms of disposition, including mineral leasing, and reserved for use for scientific, recreational, and other similar uses." Eight additional tracts (full and partial) adjacent to the Preserve were designated as "adjunct to the Ecological Preserve". These tracts have become known as the Buffer Zone and were removed from consideration for leasing by the Order. This Order reflects Department of the Interior past policy regarding OCS leasing in this area. In all, a total of approximately 55,000 acres area effected.

b. Description of the environment: The deferral area includes what in the late fifties and early sixties, was habitat for a large population of benthic tongue worms Listriolobus pelodes (Allan Hancock, 1965). More recent surveys in the general area have suggested that the population may not have maintained the large numbers (MMS, 1983). The nearshore environment contains: Naples Reef, a productive kelp area used for scientific study by University of California at Santa Barbara; Goleta Slough, also studied by UCSB; and Santa Barbara Harbour.

c. Potential impacts avoided by deferral of this subarea: Water quality in the adjunct to the Santa Barbara Channel Ecological Preserve would be protected by the deferral due to elimination of drill muds and cuttings discharge and the elimination of potential oil spill occurrences in the area. Water quality for the entire proposed lease sale area would not be significantly different however. Risks to fish, commercial fisheries and sport fisheries would be slightly less. Similarly, the risk of impacts resulting from a spill striking the breeding and roosting colonies of seabirds and harbor seal pupping grounds of Santa Cruz and Santa Rosa Islands would be slightly reduced.

The deferral will reduce the probability of oil reaching the relatively unaltered estuary Goleta Slough near Santa Barbara and the inner of northern shores of Santa Cruz Island and the shallow island shelves of the Channel Islands Marine Sanctuary. The potential impact to recreational resources, particularly around Santa Barbara, would be reduced slightly.

The adoption of the alternative would remove eight tracts from Department of Defense concern. The potential impact to visualize resources would be reduced slightly with the elimination of platforms that could be seen from shore.

d. Resource potential: In terms of quantity and quality, the geotechnical data available in the proposed deferral area area sufficient to define specific traps throughout the entire area. Structural traps have been identified in the extreme eastern, western and southern parts of the mapped areas. Stratigraphic traps may be present to the southwest part of the area. Possible exploration/discovery trends within or adjacent to the subarea include the Rincon anticlinal discovery trend and the Pital Point anticlinal discovery trend both of which extend into the area.

e. Deferral recommended by: State of California, California Coastal Commission, Santa Barbara County, Lompoc City, Get Oil Out, City of Santa Barbara.

Channel Islands National Marine Sanctuary:

a. Geographic description: The Channel Islands National Marine Sanctuary consists of San Miguel, Santa Rosa, Santa Cruz and Anacapa Islands on the outer region of the Santa Barbara Channel and Santa Barbara Islands approximately 40 miles south of the mainland coast.

The Channel Islands National Marine Sanctuary, designated on September 22, 1980, includes only the ocean area from the mean high tide line seaward to 6 nm, a total of 175 blocks approximately 479,000 acres. Hydrocarbon exploration and development activities are prohibited by regulation within the boundaries of the Channel Islands National Marine Sanctuary.

b. Description of the environment: The northern Channel Islands are important for numerous reasons. Particularly significant are the marine biological, archaeological, and paleontological resources found on the islands. For example, they contain the largest and most diverse temperate water pinnipeds, (seals and sea lions) community in the world. More than 36,900 pinnipeds, of 6 different species, were counted on the islands themselves, excluding the surrounding waters. Also, there is evidence of human inhabitants going back to 30,000 years BP, and fossils of the dwarf mammoth.

c. Potential impacts avoided by deferring this subarea: Deferral of this subarea will reduce the potential effects of an oil spill to the islands should such an event occur in that the time required for spilled oil to reach shore will increase by at least 4 to 5 hours, possibly by as much as 10 hours. During this time, a significant amount of evaporation, dissolution and weathering of the oil would occur, reducing the quantity and toxicity. Also, it would allow more time for oil spill cleanup and containment equipment to be mobilized. The oceanographic conditions off Southern California are fairly good for handling an oil spill. With this additional time, the chances of effectively protecting sensitive marine resources are increased by 4-5 hours. Specifically the sensitive intertidal and nearshore subtidal resources and pinnipeds and seabirds and their resources may be less likely to be directly contacted by the oil. Even if the oil did reach these resources, there would be less of it; it would be more weathered; and it would be less toxic.

Increasing the distance between OCS development and these resources would also reduce the vessel traffic, human intrusion and noise generated during exploration and development. Potential disruption of critical breeding and nesting activities for seabirds and pinnipeds would, therefore, be reduced. Also, the risk of damage from platforms and pipelines, to hard bottom subtidal areas, would be eliminated. Lastly, deleterious efforts for drilling muds, cutting and formation water would be reduced.

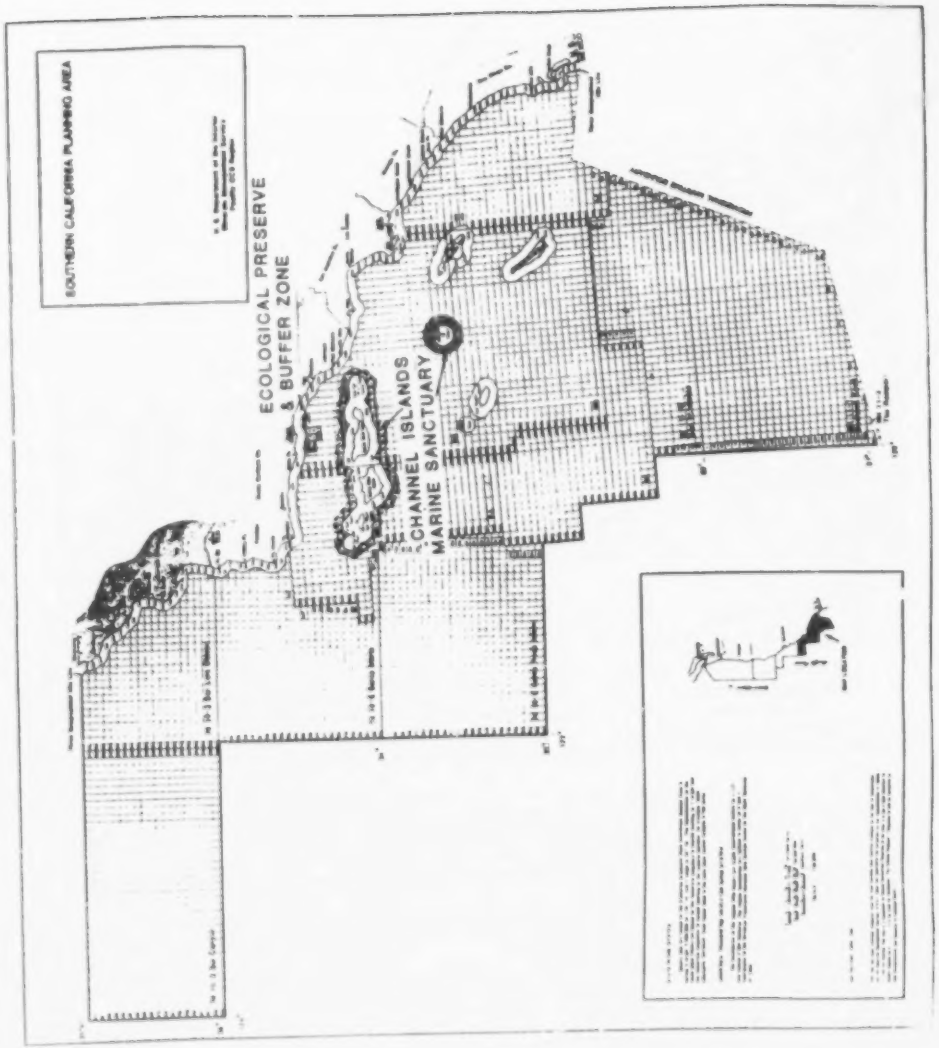
d. Resource potential: In terms of quantity and quality, the geotechnical data available in the proposed deletion subarea are sufficient to define specific traps throughout the entire area. Structural traps have been identified throughout the mapped area.

Stratigraphic traps may be present throughout the subarea.

Central California Planning Area

Possible exploration/discovery trends within and adjacent to the subarea include the Sockeye and Hueneme fields which border the northeastern corner of the area, the Santa Barbara Island anticlinal trend and a number of east-west trending faults which cross the area. Noncommercial hydrocarbons have been discovered on the northern Channel Islands.

e. Deferral recommended by: State of California, California Coastal Commission, Santa Barbara County, Lompoc City, Get Oil Out, City of Santa Barbara.



Northern California

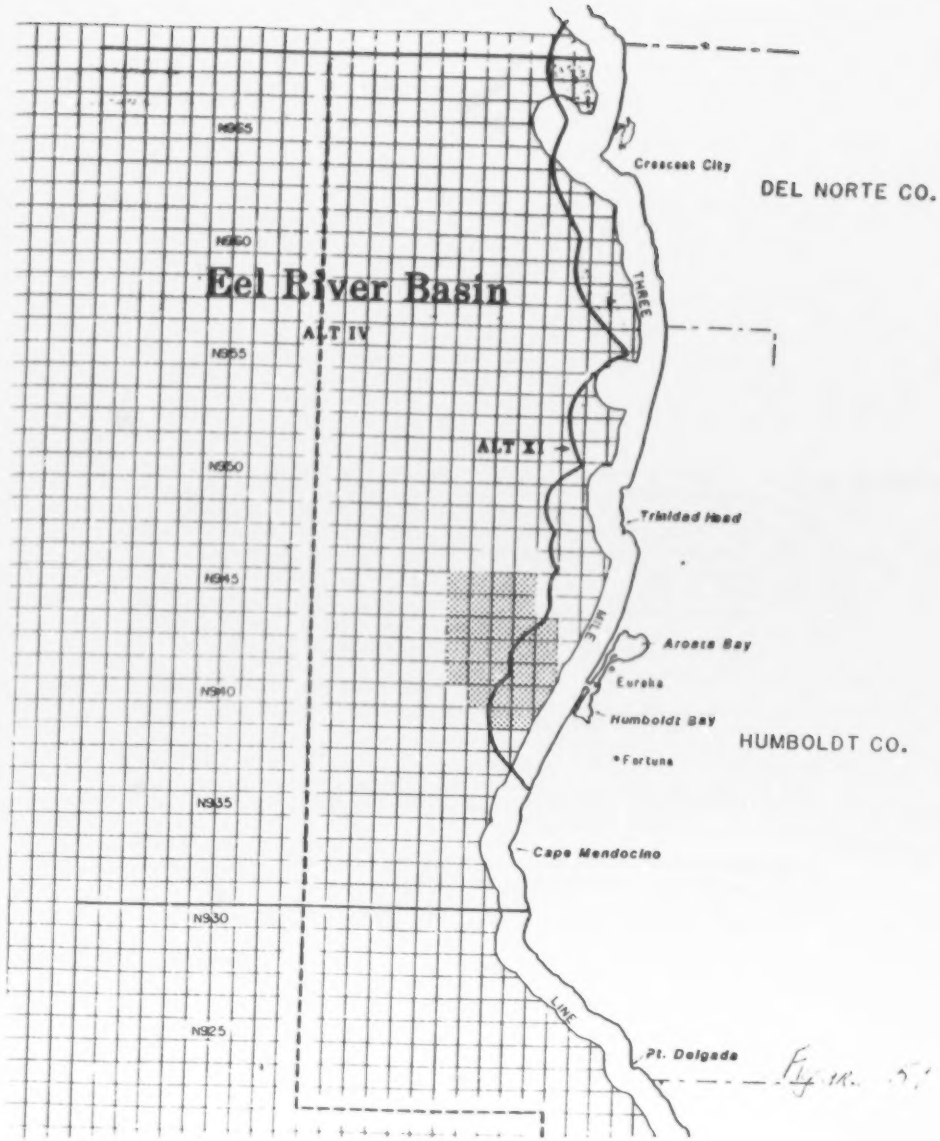
el River Basin

a. Geographical description: The Eel River Basin subarea is located off he coast of northern Humboldt County and Del Norte County. The southern oundary starts at the mouth of the Mattole River. The northern boundary is he seaward extension of the California/Oregon state line (see figure 59-1).

b. Description of the environment: Central Humboldt county consists of ow lying river deltas and bays. It is a center for dairying, fishing and imber processing. Coastal northern Humboldt County and Del Norte County are ominated by steep cliffs and forests. The Eel River Basin consists of a ariety of valuable biological, recreational, and commercial resources. iological resources include: intertidal areas, fisheries, bays, estuaries, nd migration routes. Intertidal areas include Redwood National Park ASBS, oint St. George, Pebble Beach, Patricks Point, Trinidad Head ASBS, Point elgada, Big Lagoon and Stone Lagoon. Fisheries and mariculture include: almon, steel head trout, smelt, sable fish, surf perch, flat fish, rock fish, ungenss crab, oysters, and ling cod. Major bays and estuaries are: Smith iver Delta, Lake Earl, Arcata Bay, Humboldt Bay and the Eel River Delta. arine mammals living in the area or migrating through it include gray whales, alifornia sea lion, harbor seal, harbor porpoise, and occasionally the sea tter in the southern portion of the basin. Humboldt State University also perates a marine laboratory. Major recreational resources and activities nclude: Redwood National Park, Fort Humboldt State Historic Park, beaches, ightseeing, birdwatching, clam digging, fishing, camping, surfing and boating. ommercial fishing is a major economic activity. The principal ports are ocated in Humboldt Bay and Crescent City.

c. Potential impacts avoided by deferral of this subarea: Deferral of his subarea would assure that no leasing and consequently no exploration or evelopment activities would occur in the basin. Potentially negative impacts ssociated with oil and gas development would either not occur or would be meliorated by both distance and time. Major resources afforded protection hrough this subarea deletion would include: air quality, intertidal benthos, ubtidal benthos, fisheries, marine traffic, and visual resources.

d. Deferral recommended by: State of California, California Coastal ommission, California Senate, City of Pacifica, Greenpeace, County of onterey.



Northern California

Eel River Basin Estuaries and Salmon Spawning Streams

a. Geographic description: This subarea includes all waters outside the 3-mile limit within a 10 mile radius of the mouths of salmonid spawning streams and major estuaries. There are, from south to north, the Mattole River, Eel River, Humboldt Bay, Mad River, Big Lagoon, Stone Lagoon, Redwood Creek, Klamath River, Lake Earl, and the Smith River.

b. Description of the environment: Anadramous salmonids are, and have been historically, a major symbol of, and source of income to, the northern California coastal area. Eureka and Crescent City are major commercial fishing ports, with a smaller fleet being based at Trinidad. Boats from Oregon and Fort Bragg and other southerly California ports also fish these waters. Sport fishermen fish these waters, too, but they have a much greater impact inland in the River fisheries for salmon and steelhead. Native American fisheries are also important in the Klamath River system. The economic importance of fishes and fisheries, especially salmonids, has increased drastically in recent years as timber related industries have declined.

Estuaries are major ecological transition zones, or ecotones, between fresh and salt waters. As such they contain inhabitants typical of both environments, as well as organisms adapted specifically to the estuarine environment. Humboldt Bay is the largest estuary between San Francisco Bay and the mouth of the Columbia River. It houses a major port, commercial and research maricultural activities, water fowl (including sea, shore and wading birds) rookeries, harbor seals and porpoises, extensive clam beds, and other unique habitats. The other three estuaries are intermittently open lagoons. They contain many of the same ecological characteristics of Humboldt Bay, but on a smaller scale.

c. Potential impacts avoided by deferral of this subarea: The potential for an oil spill related to offshore exploration, production, or transportation will be reduced. Oil spill related risks to fishes, fisheries, tidal areas, estuaries, scenic coastline areas, shipping, birds, mammals and invertebrates will also be reduced.

d. Resource potential: In terms of quantity and quality, the geotechnical data available in the proposed deferral area are sufficient to define specific traps in all parts of the area except for +6 percent in the east-north central parts of the area where data is only sufficient to define specific plays.

Structural traps have been identified in the mapped areas in the southern part of the area but few structural traps have been identified in the northern part.

Stratigraphic traps may be present as stratigraphic pinchouts on the flanks of structural traps in the southern part of the area.

Possible exploration/discovery trends within or adjacent to the subarea include a series of northwest oriented anticlinal trends are present in the southern part of the area. One of these trends is the westerly extension of the Tompkins Hill-Table Bluff "Discovery" Trend.

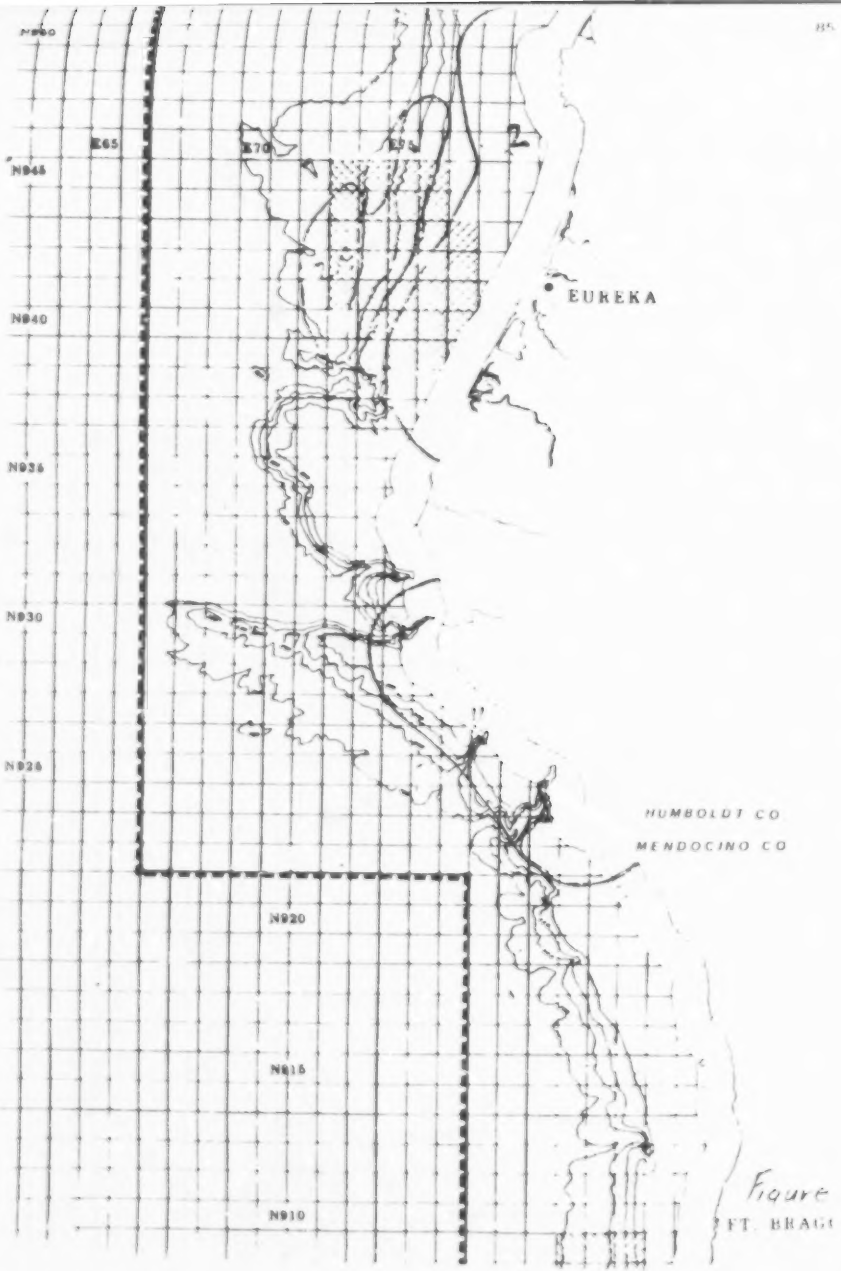
Northern California

King's Range

a. Geographic description: The King's range subarea deferral would remove approximately 30 whole or partial blocks from the offering area (see figure 11-1). The subarea is defined by a line arced 5 to 7 miles offshore from Punta Gorda in the north to the Mendocino/Humboldt county line in the south.

b. Description of the environment: The King's Range National Conservation area is a primitive area which is one of the most scenic stretches of coast in California. Recreation is minimal in the area due to the minimal access available to the area. However, this in turn increases the value of the area as a recreational resource. The shoreline is mainly composed of steep cliffs with a rocky coast, offshore stacks, and sandy beaches.

c. Potential impacts avoided by deferral of this subarea: Deferral of this subarea would reduce the potential impact to the visual quality of this pristine area as a result of a platform not being located within 5 to 7 miles of the coast. In addition, it would also reduce the potential impacts from oil spills, as any spills that may occur from oil exploration or development activities would originate further offshore. This would allow greater time for the mobilization of cleanup efforts as well as decrease the toxicity and quantity of the spilled oil (through evaporation, dispersion, sinking, weathering, and other natural processes), before possible shoreline contact.



Figure

Northern California

Point Arena Basin

a. Geographical description: The Point Arena Basin subarea is located off the coast of Mendocino county and the southern portion of Humboldt county. The southern boundary is the Sonoma/Mendocino county line. The northern boundary is the mouth of the Mattole River which is south of Cape Mendocino (see figure 58-1).

b. Description of the environment: Mendocino and the southern portion of Humboldt County are noted for their extremely rugged coastline. Much of it is undeveloped and only occasionally interrupted by small towns. The area possesses a variety of biological, recreational, and commercial resources. Biological resources include: Gray whale migration routes, osprey, whistling swans, peregrine falcon, fish spawning areas, salmon migration routes, and occasional sea otters. The coastline from Fort Bragg down to Port Rosa is considered significant for its rocky intertidal biological community. Major estuaries include: Ten mile river, Big river, and Albion river. Major recreational resources and activities include: Kings Range National Conservation Area, State parks, fishing, boating, whale watching, sightseeing, and camping. Commercially, this area is valuable for trawling for bottom fish; and trolling for salmon and albacore.

c. Potential impacts avoided by deferral of the Point Arena Basin subarea: Deferral of this subarea would assure that no leasing and consequently no exploration or development activities would occur in the basin. Thus the potentially negative environmental impacts associated with oil and gas development would either not occur or would be ameliorated by both time and distance. Major resources afforded protection through this subarea deferral would include: visual resources, estuaries, intertidal biological communities bottom fish, salmon, albacore, water quality, sportfishing and recreation.

d. Deferral recommended by: State of California, California Coastal Commission, California Senate, City of Pacifica, Greenpeace, County of Monterey.

Central California

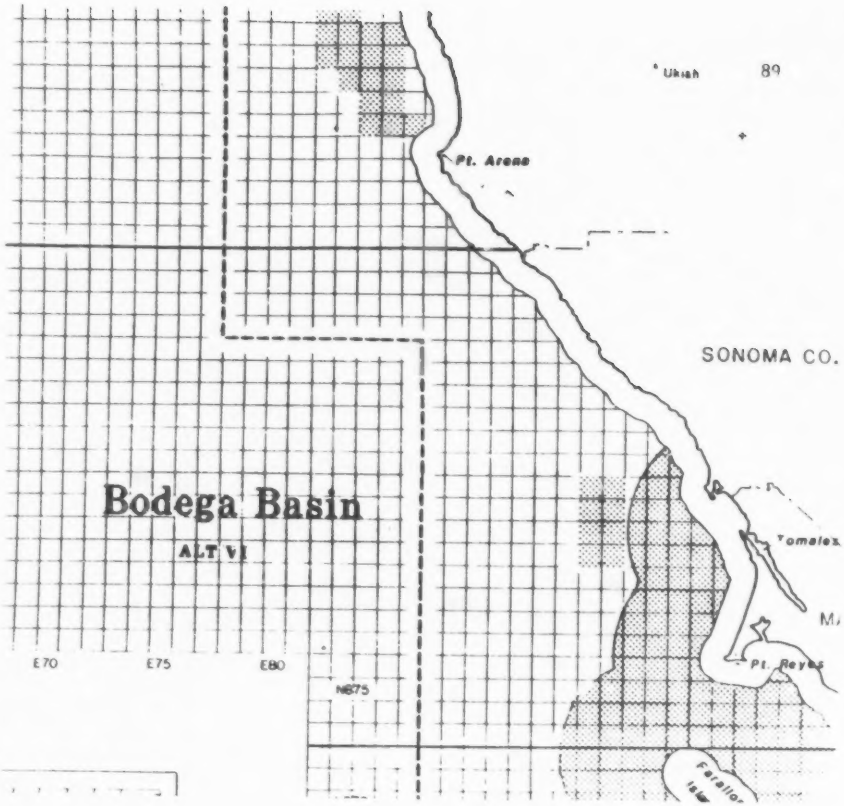
Bodega Basin

a. Geographic description: The Bodega basin subarea is located off the coast of the following California counties: Marin and Sonoma. The southern boundary is located at the mouth to San Francisco Bay. The northern boundary is at the Sonoma/Mendocino county line (see figure 57-1).

b. Description of the environment: the Bodega basin contains a variety of valuable biological, recreational and commercial resources. Biological resources include major bays and estuaries such as the mouth of the Russian River, Bodega Bay, Estero Americana, Tomales Bay, Abbots Lagoon, Limantour and Drake's Esteros, Bolinas Lagoon, and San Francisco Bay. Important intertidal areas include Bodega Head ASBS (areas of special biological significance). Important recreational resources include: Pt. Reyes National seashore, and numerous state beaches. Principal recreational activities include: fishing, boating, scuba diving, clamming, sightseeing, picnicing and hiking. Commercial activities include: tourism and fishing. Principal types of fish caught are flatfish, salmon and rock fish.

c. Potential impacts avoided by deferral of this subarea: Deferral of this subarea would assure that no leasing and consequently no exploration or development activities would occur in the basin. Potentially negative environmental impacts associated with oil and gas development would either not occur or would be ameliorated by both distance and time. Major resources afforded protection through this subarea deletion would include: estuarine and wildlife habitat in Bodega Bay, Tomales Bay, Drake's Estero and Limantour Estero; shorebird and waterfowl areas (Tomales Bay); Oyster farming at Tomales Bay and Drake's Estero; intertidal benthos; commercial fisheries; and recreation.

d. Deferral recommended by: State of California, California Coastal Commission, California Senate, City of Pacifica, Greenpeace, County of Monterey.



Central California

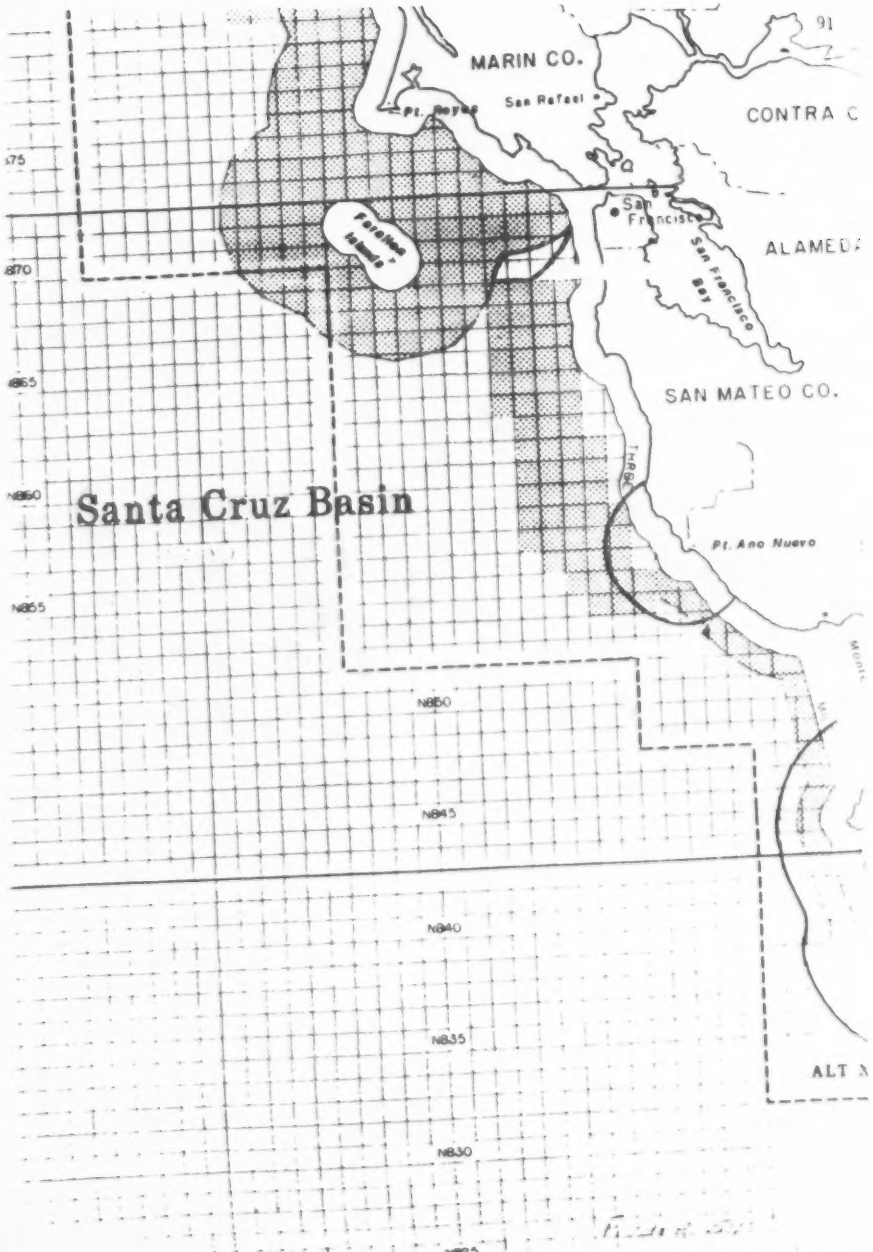
Santa Cruz Basin

a. Geographic description: The Santa Cruz Basin subarea is located off the coast of the following California counties: San Francisco, San Mateo, Santa Cruz, and the northern portion of Monterey. The southern boundary is located at Pt. Sur. The northern boundary is located at the entrance to San Francisco Bay (see figure 54-1).

b. Description of the environment: The Santa Cruz Basin contains a variety of valuable biological, scientific, recreational and commercial resources. Significant biological resources include: San Francisco Bay, James Fitzgerald ASBS (Area of Special Biological Significance), Ano Nuevo ASBS, Pt. Reyes-Farallon Islands Marine Sanctuary, Monterey Canyon, Elkhorn Slough, Moss Landing, Pescadero Creek Estuary, and Point Lobos. These areas and other coastal areas are important for their marine life, pinnipeds, sea otters, whale migration routes, seabird breeding and nesting areas, kelp beds, rocky intertidal areas, and clam beaches. Scientific facilities in the region include the Monterey Bay Aquarium, Hopkins Marine Stations, the Naval Post Graduate School, and University of California at Santa Cruz. Significant recreational resources include numerous State beaches, Golden Gate National Recreational Area, recreational boating and fishing, and scenic resources. Significant commercial resources include commercial fishing (for salmon, flat fish, rockfish and Dungeness crab), extensive marine traffic into San Francisco Bay and along the coast, and tourism.

c. Potential impacts avoided by deferral of the Santa Cruz Basin subarea: Deferral of this subarea would assure that no leasing and consequently no exploration or development activities would occur in the basin. Therefore, the potentially negative environmental impacts associated with oil and gas development would either not occur or would be ameliorated by both distance and time. Major resources afforded protection through this subarea deferral would include: water quality, ocean dumping, subtidal benthos, tourism, sportsfishing, visual resources, cultural resources, and military activities.

d. Deferral recommended by: State of California, California Coastal Commission, California Senate, City of Pacifica, Greenpeace, County of Monterey.



Central California

Ano Nuevo

a Geographical description: The Ano Nuevo subarea deferral would remove about 20 partial and 3 complete blocks from the offering area within a 10 mile buffer are seaward of Ano Nuevo Island. Point Ano Nuevo and the adjacent island area about 40 miles south of San Francisco in southern San Mateo county (see figure 3.A-1).

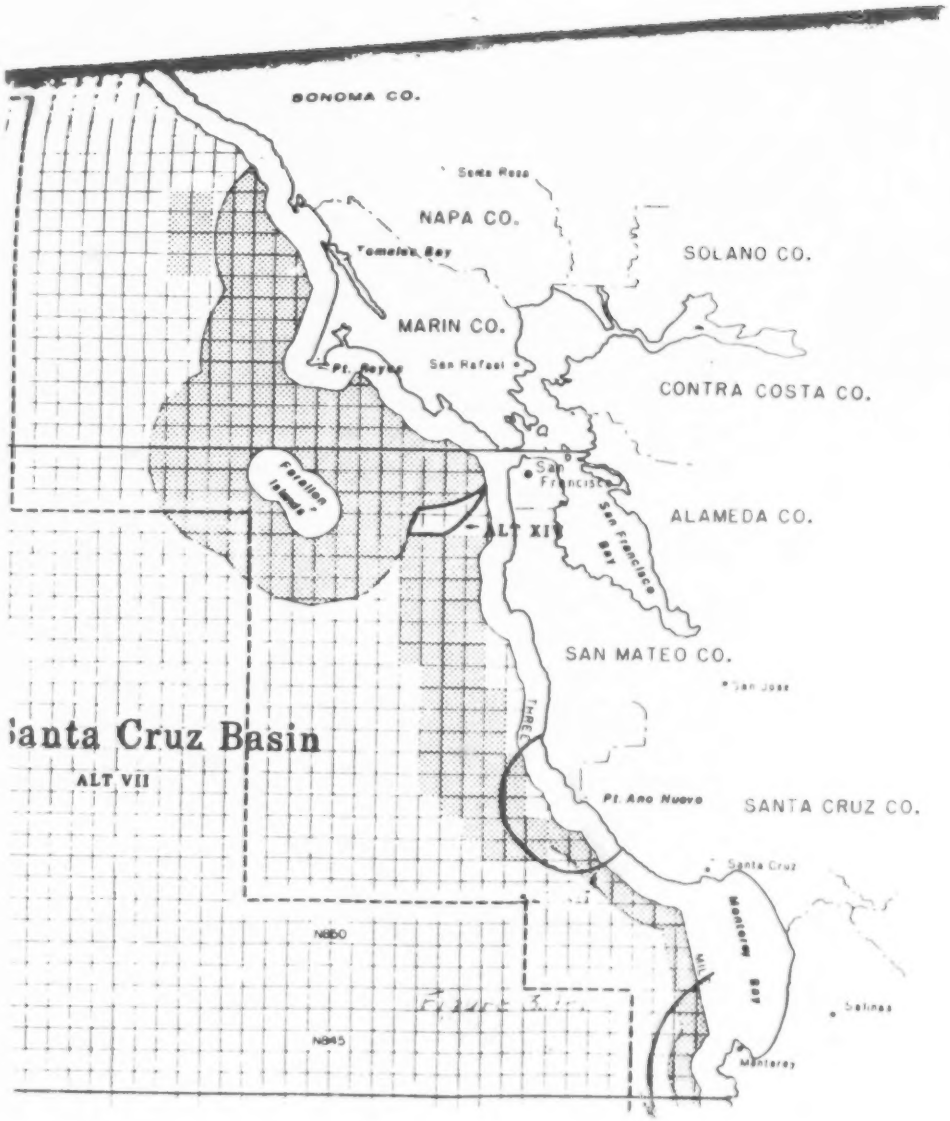
b. Description of the environment: The largest pinniped populations in central and northern California are found on Ano Nuevo Island and mainland point. Breeding populations of northern elephant seals occur in winter and Stellar sea lions in summer. Thousands of California sea lions haul out here in late spring through late autumn. Important foraging areas for California sea lions are located over the Pioneer Canyon between Ano Nuevo and Farallon Islands. Up to 2,300 Brown Pelicans roost on Ano Nuevo Island in July. The northern end of the California sea otter range is at Point Ano Nuevo. Thousands of people come to Ano Nuevo each year to see the pinnipeds.

c. Potential impacts avoided by deferral of this subarea: If this subarea is deferred, the potential platforms and their associated impacts would not be installed in the subarea. The potential impacts on air and water quality, tourism, and visual resources would be reduced. Deferral of this subarea would also provide an additional buffer zone which would allow additional time for weathering, dispersion, diversion and cleanup of oil in the event of a spill.

d. Resource potential. In terms of quantity and quality, the geotechnical data available in the proposed deferral area are sufficient to define specific traps throughout the entire area, and structural traps have been identified in the central and southern parts of the mapped area.

Stratigraphic traps may be present in the western 2/3 of the area.

Possible exploration/discovery trends within or adjacent to the subarea include the Rose Canyon Fault Trend in the eastern part of the area and possible southerly extension of the Newport-Inglewood Fault/Anticlinal Discovery Trend.



Nuclear Waste Dump Sites

a. Geographic description: This subarea deferral would remove five areas from the proposed lease offering. One area is situated 21 miles south of Santa Cruz Island and is comprised of 21 partial and complete tracts (see figure 50-1). Another area is approximately 142 partial and complete tracts. Three sites are situated off the Farallon Islands in 900, 1700 and 2400 m (see figure 50-2). These sites ranges from 25 to 60 miles off San Francisco at 37°38'N 123°08'W, 37°37'W 123°12'W and 37°39'N 123°26'W, respectively. The exact number of tracts involved with the Farallon Island sites are unknown as only the central coordinates and the approximate total area are known.

b. Description of the environment: These five areas are open ocean areas which were designated as low level radioactive waste dump sites. Dumping of low level waste is documented for four of the sites, but no record shows any dumping of low level radioactive waste at the Pt. Arguello site. The Pt. Arguello site did, however, receive conventional and chemical munitions and should be considered a hazardous area for bottom disturbing activity.

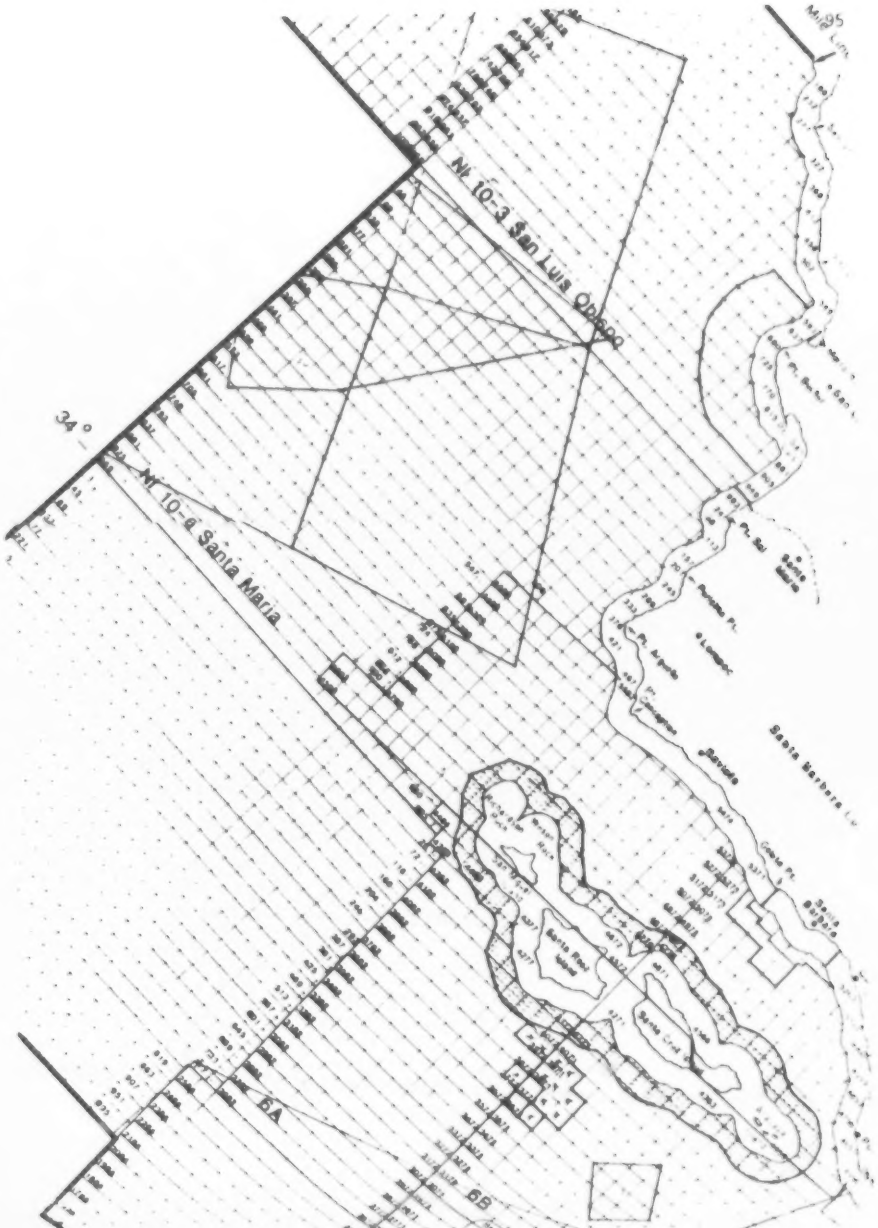
The Santa Cruz site received 3114 containers of lower level waste with a combined radioactivity of 108 curies between 1946 and 1982.

The Farallon Island sites received approximately 99 percent of the radioactivity dumped in the Pacific, which was approximately 47,500 containers with a radioactivity level of 14,500 curies, with dumping occurring from 1946 to 1970.

These sites should be considered as hazardous areas for any bottom disturbing activity, due to the potential increased release of radioactivity to the marine environment.

c. Potential impacts avoided by deferral of this subarea: Deferral of this subarea would remove the potential of bottom disturbing activities from these areas, thus reducing the potential impact of increased release of radionuclei into the marine environment.

d. Deferral recommended by: California Coastal Commission.



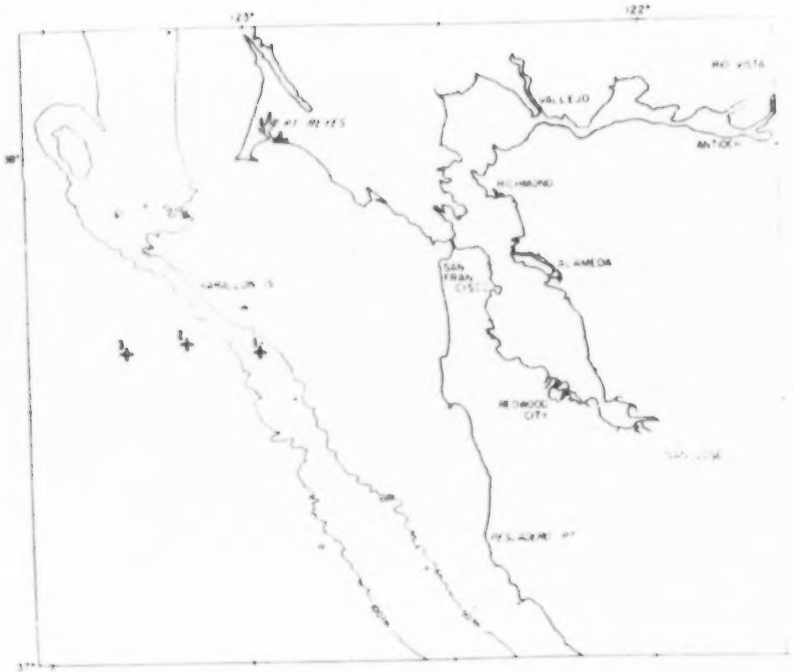


FIGURE 50-2
FARALLON ISLAND WASTE DISPOSAL SITES

Southern California

Congressional Moratorium - Southern California

a. Geographic description: The subarea deferral would eliminate 270 whole or partial blocks from the offering area (see figure 10-1). The area is defined by the appropriations bill passed by the 98th Congress and signed by the President on November 4, 1983 (PL 98-148, Sec. 113, 1983). The appropriations bill for FY 1984 required the deferral of blocks off Santa Monica Bay, Los Angeles County, Orange County, and San Diego County. The blocks are within an area located off the coastline of the State of California from the seaward extension of the Los Angeles County/Ventura County line southeast to California/Mexico border extending from 3 to 27 miles offshore.

b. Description of the environment: Santa Monica Bay is the largest bay in southern California, and is known for its sensitive rocky intertidal areas, and recreational value (see specific subarea deletions for Santa Monica Bay). San Diego, within this subarea, plays a significant role in local and regional economics through recreational uses and tourism. The U.S. Navy, Air Force, and Marines also utilize major portions of this area. These are also potentially significant biological resources within the area (see specific subarea deferrals for Military subarea and San Diego County subarea). Recreational use of the Orange County coastline is a significant part of the local and regional economy. There are also several coastal areas that are biologically sensitive (see specific subarea deferrals for Orange County).

c. Potential impacts avoided by deferrals of this subarea: Deferral of the blocks off the Santa Monica Bay area and Orange and San Diego Counties would reduce the local impacts to military use areas. In addition, the deferral of nearshore blocks would allow additional time for weathering, diversion, and cleanup of an exploration or development related oil spill should such an event occur. Potentially adverse visual effects associated with hydrocarbon development would be reduced within the subarea.

Impacts to water quality, ocean dumping, and air quality would be reduced. The biological resources that would be afforded protection are: intertidal benthos from the Los Angeles/Ventura County line to the California/Mexico border; anchovy and squid populations, cetaceans near Point Dume, Point Fermin and San Diego; seabird feeding and concentration areas off Point Mugu and Santa Monica Bay; wintering, nesting, and migratory birds in Anaheim Bay, migratory waterfowl and seabirds off San Diego. Threatened and endangered species protected by the deferral include: gray whales; least tern colonies; brown pelicans; light-footed clapper rails; California black rails; sea turtles; and salt marsh birds beak (plant), as well as estauries in the area. Commercial fisheries, recreational and cultural resources would also be afforded protection.

d. Deferral recommended by: State of California, Association of Monterey Bay Area Governments, Desomount Club, Natural Resources Defense Council.

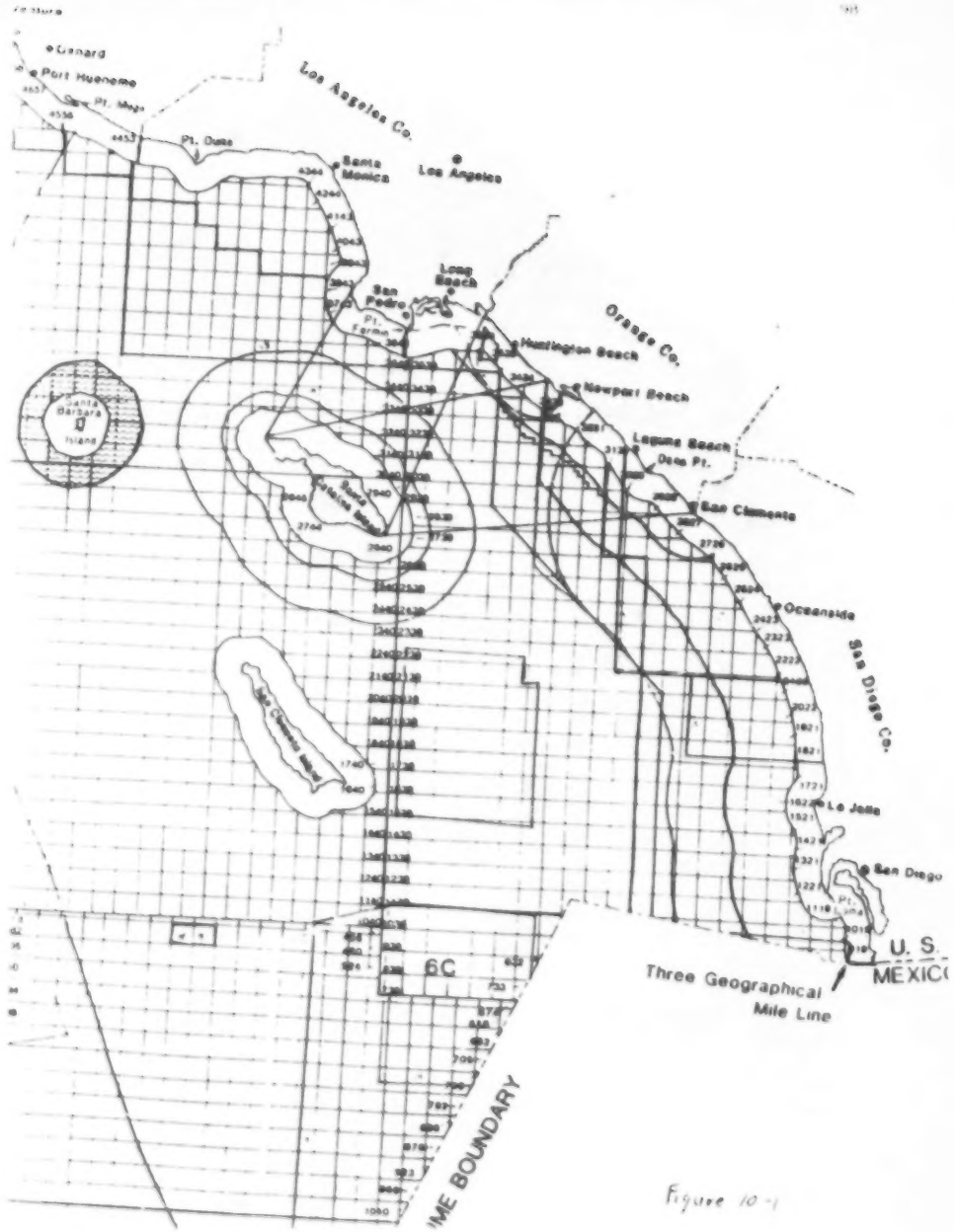


Figure 10-1

Southern California

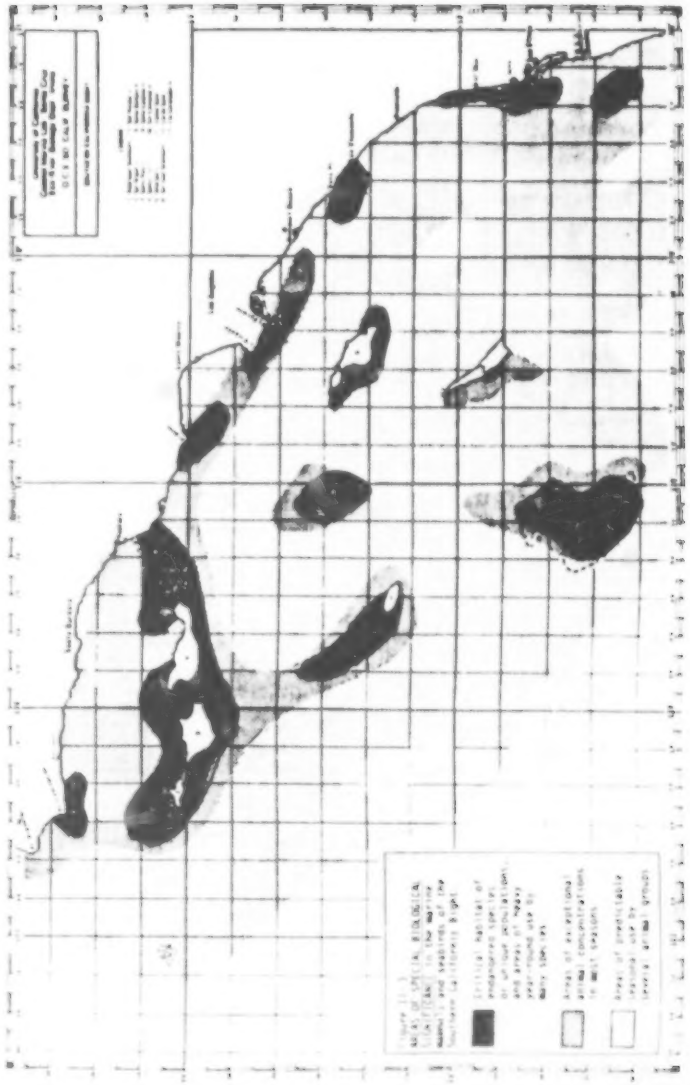
Areas delineated by U.C. Santa Cruz as critical habitat for endangered species or unique populations

a. Geographic description: All of these areas are found in the Southern California Bight (SCB) (see figure 9-1) and include all of the SCB islands with a buffer area of 6-12 miles around them, the Tanner-Crutes Banks, Point Conception, Point Dume, Palos Verdes Peninsula, the coast from Dana Point south to San Clemente, waters of Point Loma north to northern San Diego County, and parts of the Santa Rosa Ridge.

b. Description of the environment: The Southern California Bight islands contain the worlds largest California sea lion and northern elephant seal rookeries and the only northern fur seal rookery in the U.S. outside of Alaska. The islands and offshore banks and ridges are used quite heavily by the migrant and resident seabirds that frequent this area. The nearshore coastal areas are used frequently by cetaceans especially the gray whales.

c. Potential impacts avoided by deferral of this subarea: This subarea deferral would eliminate potential OCS oil and gas activities in a number of area considered critical for the wellbeing of the local population of a number of different marine mammal and seabird species. Potential effects of oil and gas operations such as noise, water and air quality degradation, and potential oil spills would be eliminated. The species receiving the most benefits from this deferral would probably be the northern fur seal, brown pelican, and Cassins auklet.

d. Deferral recommended by: University of Santa Cruz.



Southern California

Defer area within 20 miles offshore San Diego County

a. Geographic description: This subarea deferral would remove approximately 162 complete and partial blocks from the proposed planning area. These tracts are located within twenty miles of the San Diego County coastline (see figure 25-1).

b. Description of the environment: The San Diego County shoreline plays a significant role in local and regional economics through recreational beach use and tourism. It is estimated that recreational beach use in San Diego County is in excess of 20 million recreationists per year, with an estimated value in excess of $122 million in 1980. Tourism is also significant in that it was estimated to be excess of $557 million in 1980.

The U.S. Navy, Air Force, and Marines utilize the San Diego harbour area and large portions of the nearshore area for training exercises and testing of equipment and personnel. Significant biological areas; wetlands, estuaries, rocky intertidal areas, exist along the coast which could suffer significant impacts should an oil spill occur and contact the coast. Endangered species are known to utilize or inhabit the wetlands and estuaries along this coast. These species could also suffer significant impacts should an oil spill occur and contact the coast.

c. Potential impacts avoided by deferral of this subarea: Deferral of this subarea would reduce the potential local impact to visual resources as no platform would be situated in the subarea. This in turn would reduce the potential impacts to recreation and tourism. Deferral of this subarea would provide protection for a significant number of resources by allowing additional time for weathering, diversion and clean-up of an oil spill should such an event occur. Specific resources provided protection would be: 1) Recreation resources, including tourism and visual resources; 2) Military use areas; 3) Estuaries and wetlands; 4) Biologically significant areas; 5) Rocky intertidal areas; and 6) Endangered and threatened species.

d. Deferral recommended by: State of California, California Department of Justice, City of Oceanside, Monterey County

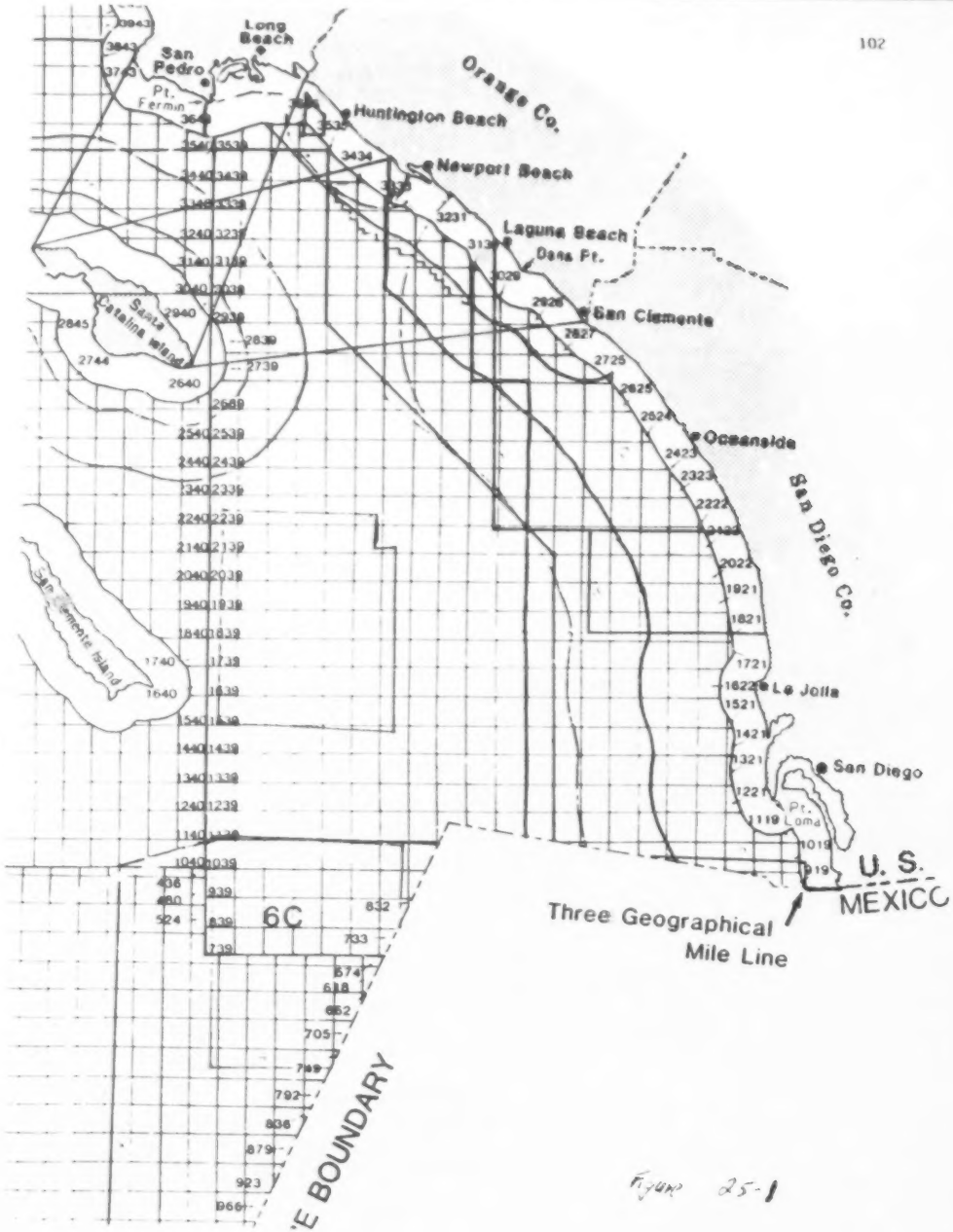


Figure 25-1

Southern California

Defer nearshore tracts from 3 to 27 miles off San Diego County

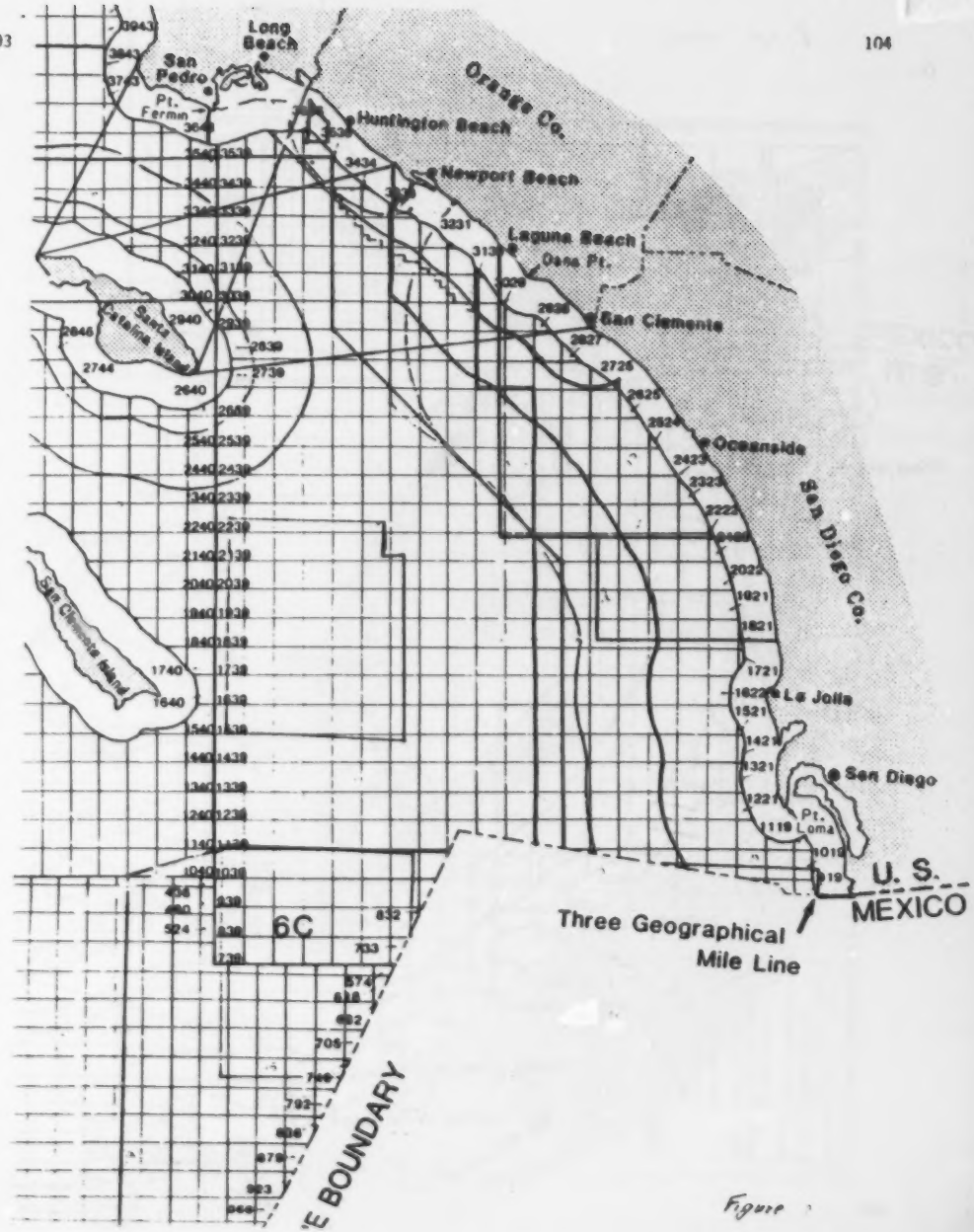
a. Geographic description: This subarea deferral would remove 138 complete and partial tracts from the proposed planning area. These tracts are located from three to 27 miles offshore from Dana Point in the north to the U.S./Mexico border in the south (see figure 26-1).

b. Description of the environment: The San Diego county shoreline plays a significant role in local and regional economics through recreational beach use and tourism. It is estimated that recreational beach use in San Diego county is in excess of 20 million recreationists per year, with an estimated value in excess of $122 million in 1980. Tourism is also significant in that it was estimated to be excess of $557 million in 1980.

The U.S. Navy, Air Force, and Marines utilize the San Diego harbour area and large portions of the nearshore area for training exercises and testing of equipment and personnel. Significant biological areas; wetlands, estuaries, rocky intertidal areas, exist along the coast which could suffer significant impacts should an oil spill occur and contact the coast. Endangered species are known to utilize or inhabit the wetlands and estuaries along this coast. These species could also suffer significant impacts should an oil spill occur and contact the coast.

c. Potential impacts avoided by deferral of this subarea: Deferral of this subarea would reduce the potential local impact to visual resources as no platform would be situated in the subarea. This in turn would reduce the potential impacts to recreation and tourism. Deferral of this subarea would provide protection for a significant number of resources by allowing additional time for weathering, diversion and clean-up of an oil spill should such an event occur. Specific resources provided protection would be: 1) Recreation resources, including tourism and visual resources; 2) Military use areas; 3) Estuaries and wetlands; 4) Biologically significant areas; 5) Rocky intertidal areas; and 6) Endangered and threatened species.

d. Deferral recommended by: State of California, California Department of Justice, City of Oceanside, Monterey County



Figure

Southern California

Deferral areas within 100 miles of San Diego County coastline

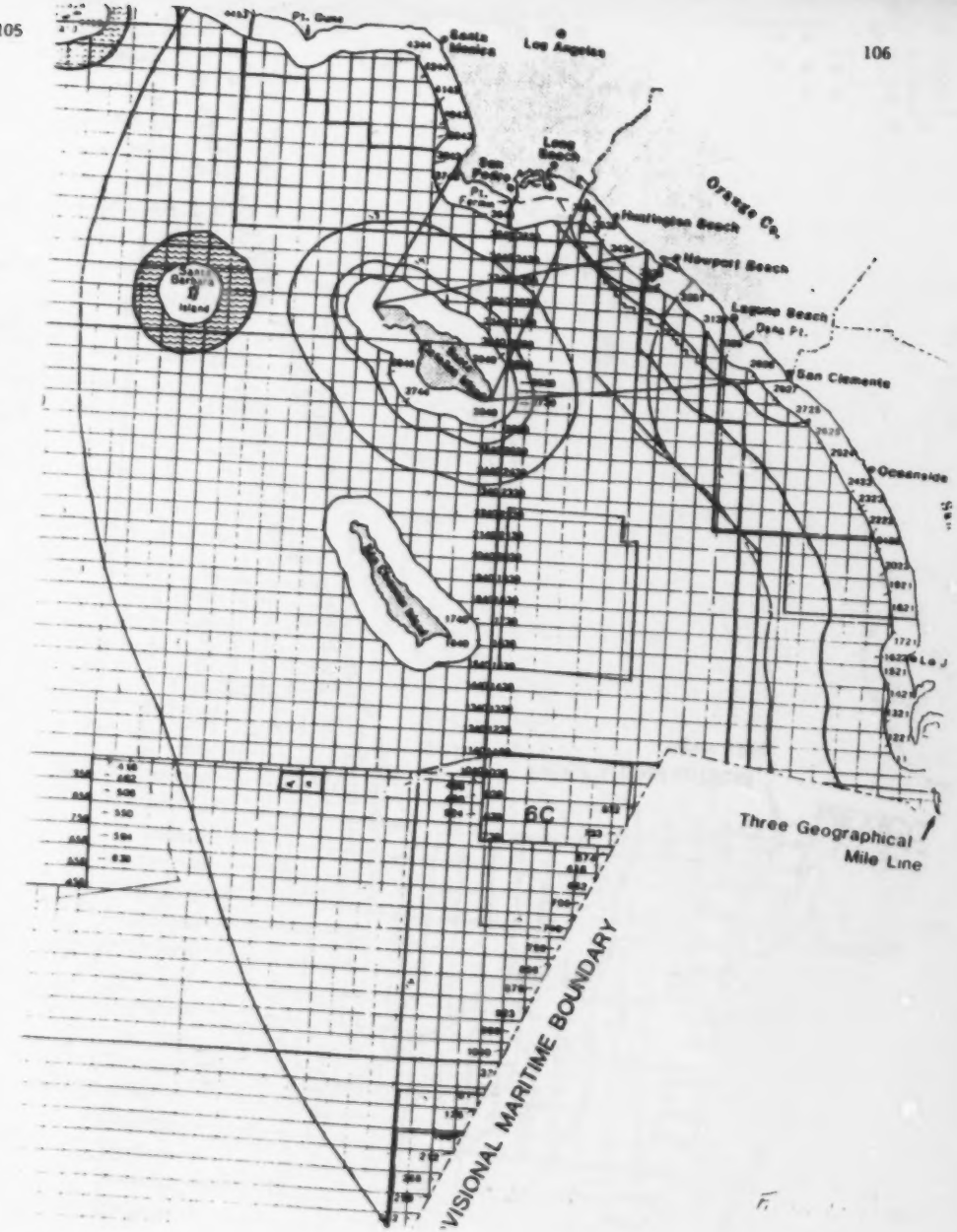
a. Geographic description: This subarea deferral would remove approximately 1259 complete and partial tracts for the proposed planning area. The tracts are located within 100 miles of the San Diego coastline (see figure 27-1).

b. Description of the environment: This area encompasses the open ocean out to 100 miles from shore, from the U.S./Mexican border to Point Mugu. The description of the environment of this subarea is described in the Santa Monica Bay and San Diego County subareas.

c. Potential impacts avoided by the deferral of this subarea: Deferral of this subarea would reduce potential local impacts to resources as described for the Santa Monica Bay and San Diego County subareas.

d. Deferral recommended by: City of San Diego

READEX



Southern California

Southern San Diego County

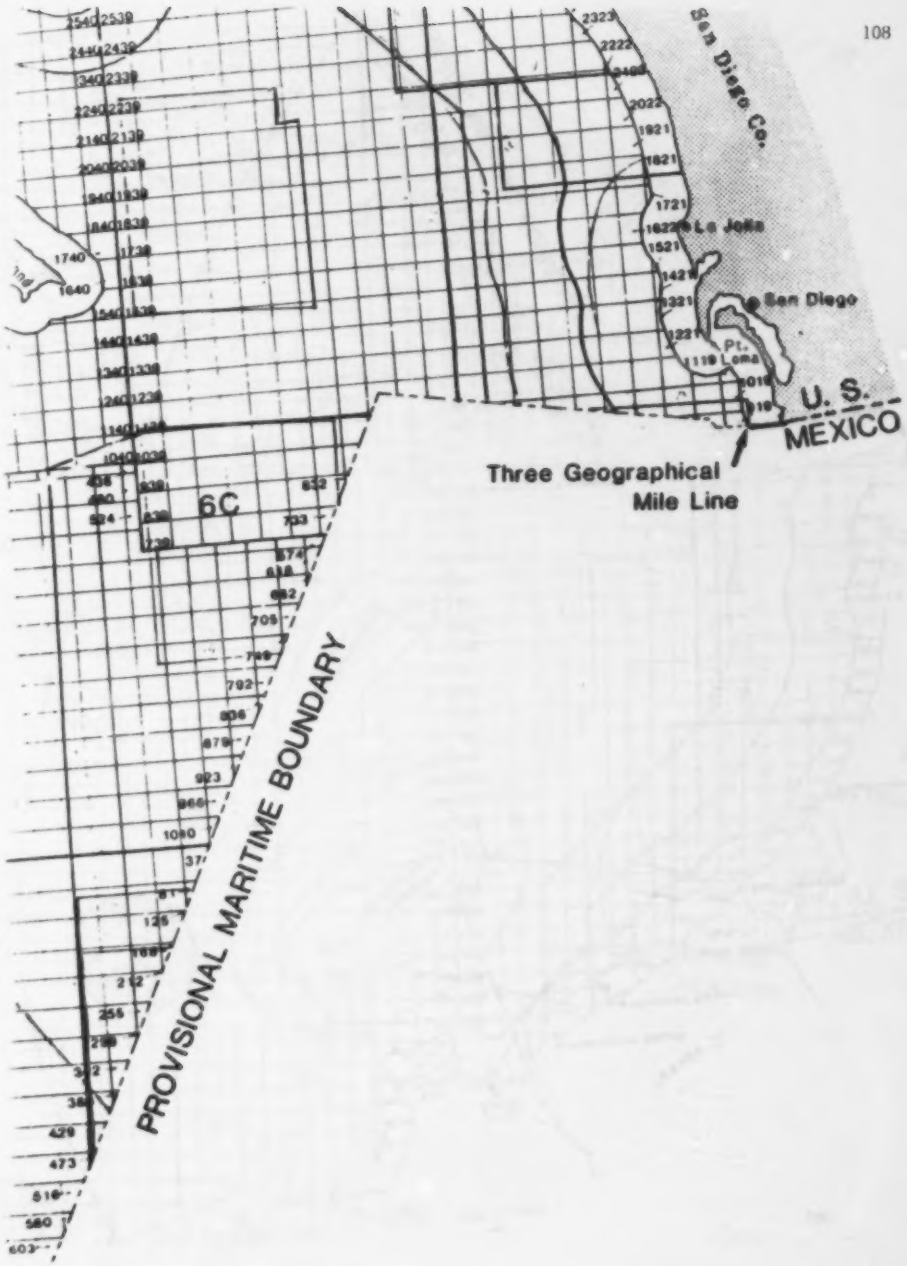
Geographic description: The southern San Diego County subarea deferral would remove approximately 40 complete and partial blocks from the offering area see figure 3-1. Southern San Diego County is bounded by the U.S. Mexican border in the south and Escondido creek in the north. The offshore boundary of the subarea is defined by a line arced 10 miles offshore from Point Loma in the south to Point La Jolla in the north.

b. Description of the environment: The southern San Diego County shoreline plays a significant role in local and regional economics through recreational beach use and tourism. It is estimated that recreational beach use in the greater San Diego area is in excess of 20 million visitations per year with an estimated value of $122 million in 1980. Tourism is also significant with an estimated value of $577 million in 1980. This is due in part to the climate and in part to the visual quality of the coast in this area. Point Loma and La Jolla are rated as highly scenic areas. The U.S. Navy, Air Force, and Marines utilize the San Diego harbor area and large portions of the nearshore area for training exercises and testing of personnel and equipment. Significant biological areas, i.e., wetland, estuaries, and rocky intertidal areas, exist along the coast which could suffer significant impacts should an oil spill occur and contact the coastline. Endangered species such as least terns, light footed clapper rails and Belding savannah sparrow are known to utilize or inhabit the wetlands and estuaries along this coast.

c. Potential impacts avoided by deferral of this subarea: Deferral of this subarea would reduce visual effects in Southern San Diego county as no platforms could be situated within 10 miles of land. This would reduce the potential effects on recreation and tourism.

Deferral of this subarea would increase protection for a number of resources in southern San Diego County by ensuring no platforms are installed in the subarea, and by ensuring additional time for weathering, diversion and cleanup of an oil spill should such an event occur. Specific resources provided protection would be: 1) Military use areas around San Diego; 2) Estuaries and wetlands (Penasquitos Lagoon, San Dieguito Lagoon, Mission Bay, San Diego Bay and Tijuana River); 3) Biologically significant areas (Point Loma Reserve, San Diego-La Jolla Ecological Reserve, Sand Diego Marine Life Refuge, and Tijuana River National Estuarine Sanctuary); 4) Rocky Intertidal areas (Point Loma to La Jolla): 5) Endangered species (least tern, light-footed clapper rails, Belding's savannah sparrow, California black rails, sea turtle, and salt marsh birds beak); and 6) Recreational resources.

d. Deferral recommended by: See specific subareas adjacent to San Diego County.



Southern California

Tanner and Cortes Banks

a. Geographic descriptions: Tanner and Cortes Banks are located near the terminus of the Santa Rosa-Cortes ridge approximately 111 miles and 115 miles respectively from the California coast (see figure 10-1).

b. Description of the environment: Interstate Electronics Corporation (1979) conducted a survey for the Bureau of Land Management on Tanner and Cortes Banks and found the hard bottoms could be divided vertically into five highly productive benthic communities based on macroalgae. Interstate Electronics concluded that the banks are situated at the edge of the continental shelf, and lie along an interface between open-ocean currents and the southern California gyre. Deepwater mixing and variable relief produce upwelling and surge as deep as 100 m (330 ft.). Limited temperature data, the influence of the California Current, and species extensions from northern populations suggest that banks may represent an area of decreased overall water temperature. These conditions combined with high water clarity in areas of rocky substrate produce an area of high productivity with macroalgae occurring in high density down to 60 m. Evidence of this high productivity is also seen in the abundant and diverse fish, coral, sponge, echinoderms, and molluscs.

Of major biological significance is that the depth ranges and deepest depths of occurrence of some communities and species are greater on the banks than has been previously noted for the Southern California Bight. The extreme water clarity results in the expansion of algal community depths from less than 50 m to over 100 m. Corals showed range extensions into shallower waters as compared to both northern and southern populations probably as a result of the banks location between open ocean currents and the southern California gyre.

Tanner and Cortes are an important area of overlap of northern and southern species distributions. The extension of depth ranges of many species and the high diversity of corals and other organisms in the area demonstrates that the banks act as an important refuge for many Southern California Bight organisms currently disappearing from more heavily impacted nearshore.

The most significance species on the banks in terms of oil development sensitivities is the dominant hydrocoral Allopora californica. It was found to be patchy throughout its depth distribution of 18 to 123 meters, but was most frequently seen between 27 and 72 meters. Allopora has limited reproductive distributional capabilities (Ostarello, 1973) and is found only at a few other locations in the Southern California Bight (only at two other locations on the OCS).

c. Potential impacts avoided by deferral of this subarea: Deferral of this subarea would reduce impacts to water quality in the area since no platforms will occur. The principal impacts avoided would be the reduction of impacts to the productive hard bottom community and the rare hydrocoral Allopora californica.

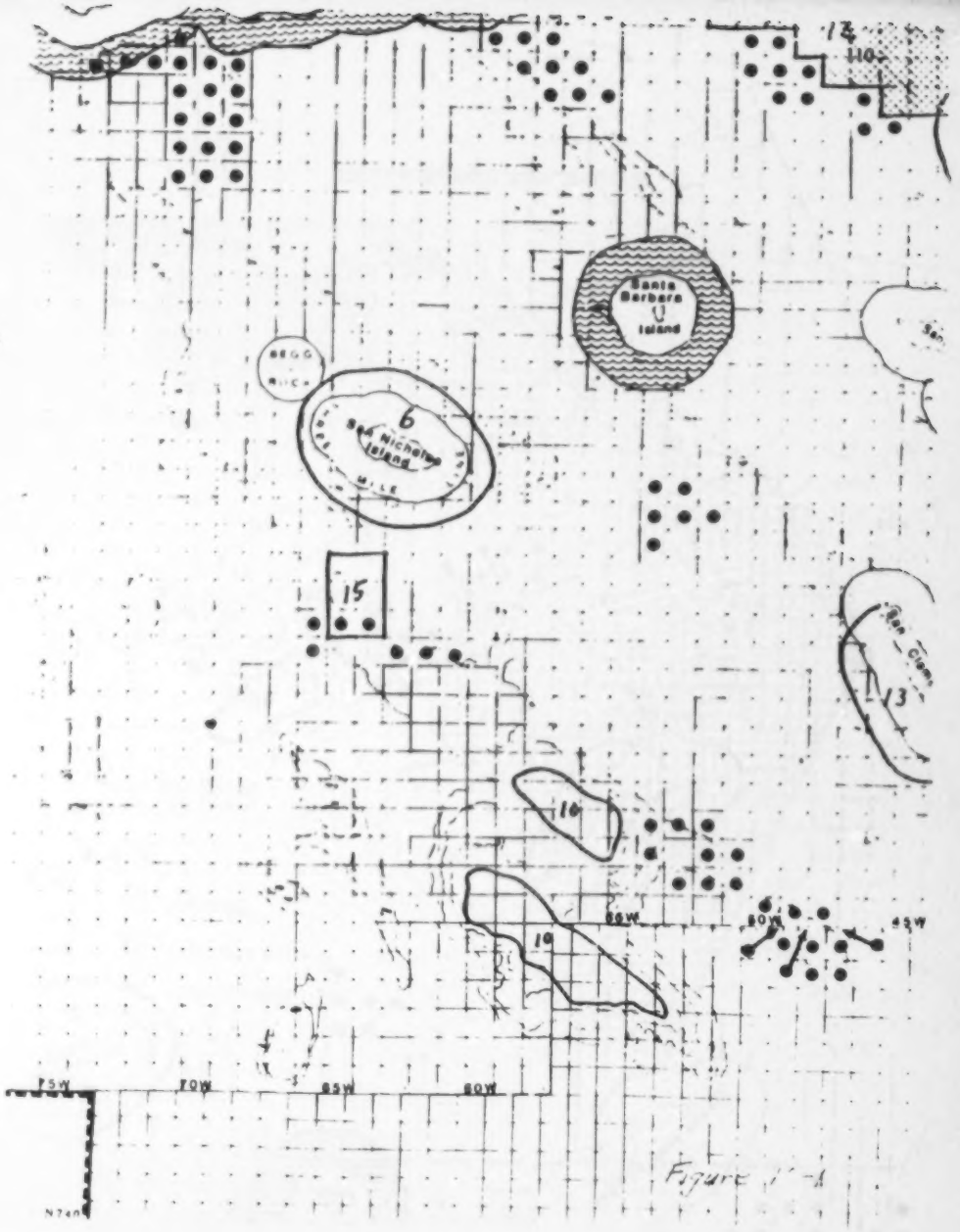


Figure 10-1

Southern California

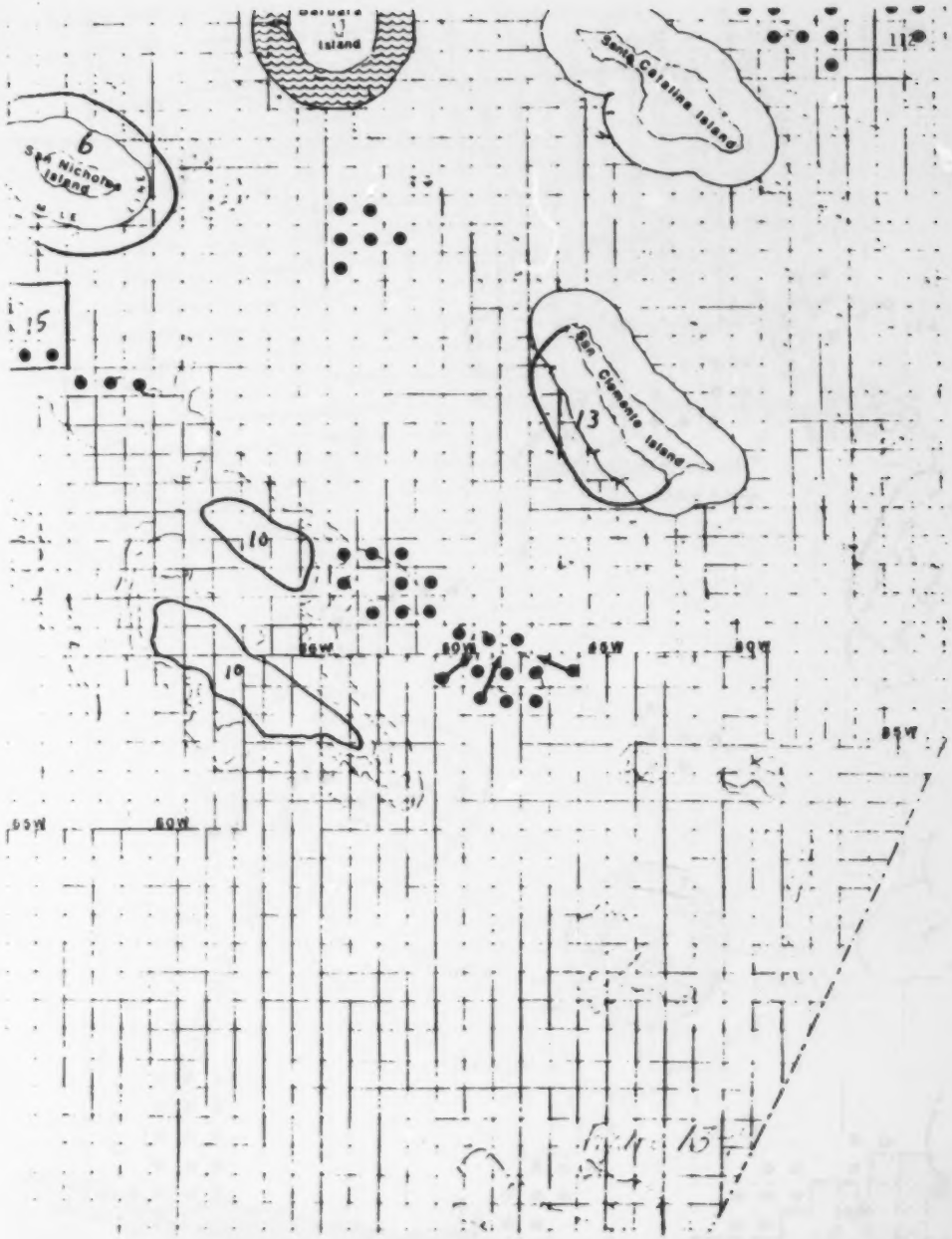
San Clemente Island (southwest side)

a. Geographic description: San Clemente Island is the southern most of the southern California offshore islands and is located approximately 22 miles south of Santa Catalina Island. Deletion of this subarea would eliminate approximately 13 whole and partial blocks (see figure 13-1).

b. Description of the environment: Littler (personal communication) observed the rich invertebrate and macroalgae populations on the southern coast of San Clemente Island. The nearby sampling station on the northwest corner of San Clemente Island had the highest mean percentage coverage of macroalgae of any of the 22 island and mainland coast stations (Littler, 1979). The station had the second most invertebrate and macroalgae species of any island station (third overall). The species distribution represents the closest affinity to the southern Baja intertidal species.

c. Potential impacts avoided by deferral of this subarea: Deferral of the 3 miles of Federal water south of San Clemente Island will reduce impacts to water quality in the area since no platform will occur. The water quality of the area is currently thought to be unaltered and pristine with respect to anthropogenic influences.

The main purpose of the San Clemente subarea deferral would be mitigative. The deferral of this area would allow more time for weathering of spilled oil and additional time for deployment and operation of oil diversion or cleanup equipment before an oil spill reaches valuable or sensitive biological resources of San Clemente Island. The 6-mile protection zone would allow: (a) 12 hours for oil spill cleanup equipment to be deployed and 6 hours for cleanup activities in 15-knot winds before oil reaches shore. The U.S. Coast Guard and MMS Memorandum of Understanding concerning oil spill cleanup requirements require cleanup activity capabilities to take 6 - 12 hours, weather permitting.



Southern California

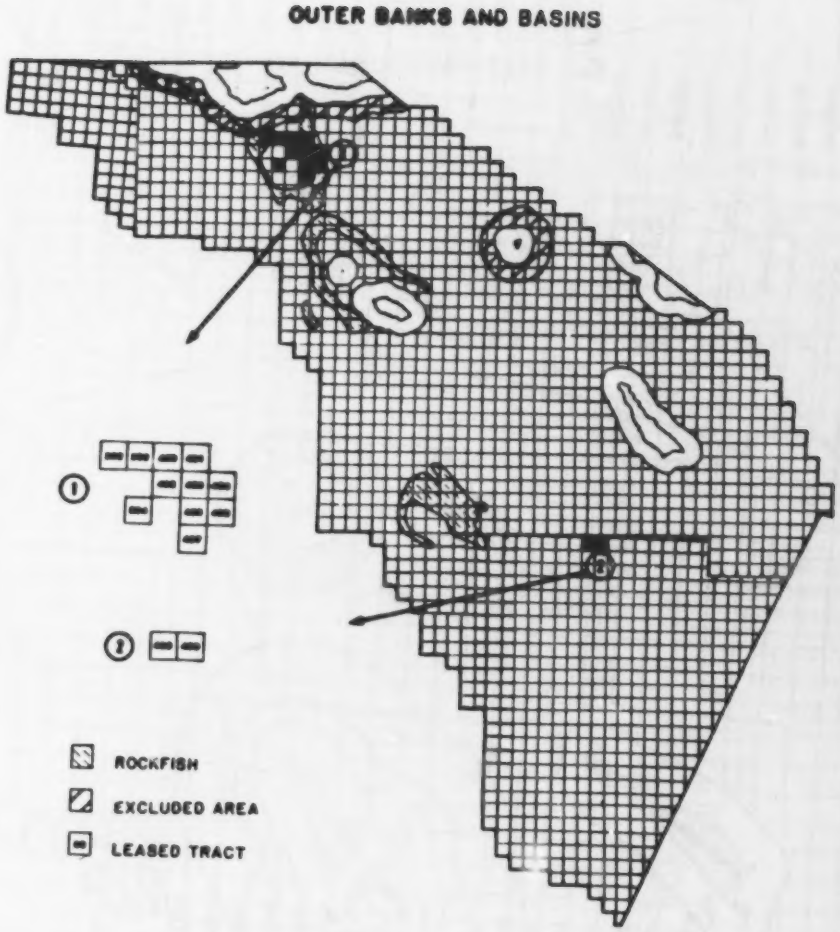
Fisheries Tracts South of Santa Rosa Island

a. Geographic description: This subarea deferral covers major commerical trawling grounds for rockfish on the Santa Rosa-Cortez High (Bank) in the Outer Bank and Basins province. It includes all or part of 104 lease blocks. (see figure 42-1).

b. Description of the environment: Rockfish (Sebastes spp.) are usually fished for by trawling though occasionally by hook and line. Trawlers drag a closed-end, funnel-shaped net over the bottom, following depth contours, to catch rockfish and other bottom residents. Rockfish are commonly fished for at depths of 145-365m (480-1200 ft.) during all months of the year. The trawl fishery is vulnerable to impacts from oil and gas activities. Fishermen from Morro Bay to San Diego fish these areas. Rockfish are a major portion of the fresh and fresh-frozen local seafood market, especially because of their year-round availability.

c. Potential impacts avoided by deferral of this subarea: Potential disruption of commercial fishing by seismic exploration, exploratory drilling, and hydrocarbon production and transportation would not occur in the deferred area. The principal impacts avoided would be gear interference from towed seismic arrays, anchor patterns, platform structural elements, pipeline laying and increased vessel traffic. Direct damage to rockfish populations and supporting food webs (which would reduce commercial catches) from potential oil spills would also be reduced, but such accidents in adjacent areas could still result in negative impacts to these areas.

d. Deferral recommendee by: Monterey County, California Coastal Commission.



Commercial fishing trawl grounds(Outer Banks and Basins).

Southern California

San Nicolas Island

a. Geographic Description: San Nicolas Island is 72 miles south of the City of Ventura. This subarea consists of a 6 mile protection zone around the entire island (see figure 6-1). This would result in approximately 43 whole or partial blocks being removed from oil and gas leasing.

b. Description of the environment: San Nicolas Island has a large pinniped rookery second only to San Miguel Island in importance within the Southern California Bight. A significant portion of the sea lion population of the Bight breed and pup on San Nicolas Island. In addition, there are also approximately 2,5000 elephant seals inhabiting the shores of the island. Both species utilize the surrounding waters for feeding.

Sand Nicolas Island, particularly on its northwest corner, has the largest concentration of tidepools in the Southern California Bight. The tidepools are extremely rich and diverse and could be significantly impacted by an oil spill. The northern sea cucumber Cucumaria pseudocarata has been found intertidally only here and on Santa Barbara Island (Littler, 1979).

c. Potential impacts avoided by deferral of the San Nicolas Island subarea: Deferral of this subarea would have the effect of assuring that no leasing and consequently no exploration or development activities would occur within 6 miles of San Nicolas Island. Thus the negative environmental impacts associated with oil and gas development would either not occur or would be ameliorated by both distance and time. For example, should an oil spill occur it would happen outside of this subarea. This would allow for additional time for cleanup, containment, and weathering of the oil before it drifts unto San Nicolas Island.

Resource Categories which will be afforded additional protection through this subarea deferral would include: Intertidal benthos, subtidal benthos, fish resources, Marine mammals, threatened endangered species, commercial fisheries, recreational resources, areas of special concern, and cultural resources.

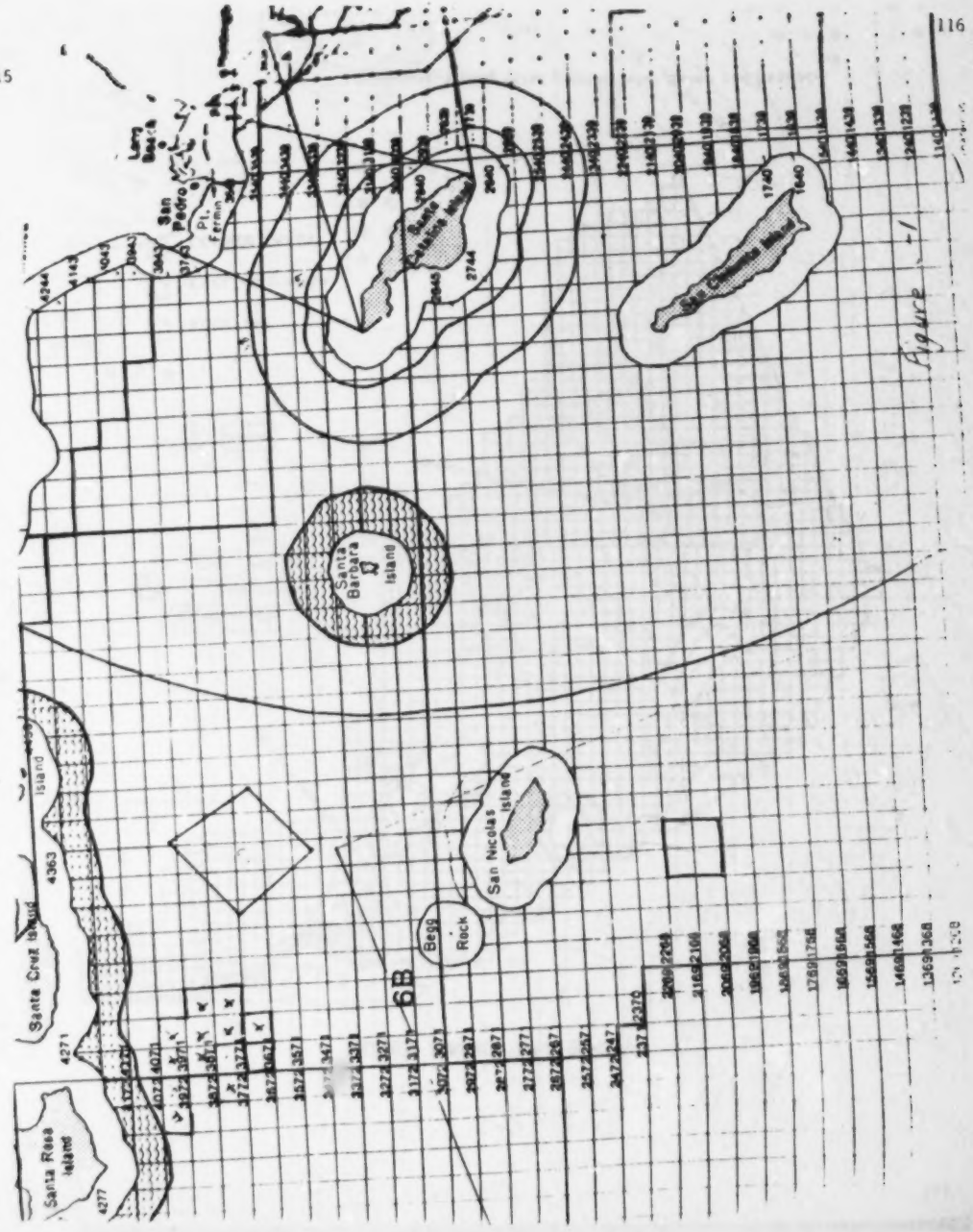


Figure 6-1

Southern California

Santa Rosa Cortes Ridge-(Vema area)

a. Geographic description: The Vema subarea on the Santa Rosa-Cortes Ridge would remove 4 blocks from the offering area (see figure 41-1). The area is located approximately 28 miles south of San Nicolas Island and 30 miles northwest of Tanner Bank.

b. Description of the environment: Santa Rosa-Cortes Ridge is a rise that extends from the Santa Rosa Island area and runs southeast past Cortes Bank. It is believed to be productive by virtue of its well developed predator trophic level in the soft bottom community (Fauchald and Jones, 1978). It is also believed to be the type of habitat for the fossil limpet Vema hyalina (McLean, 1979). Vema belongs to the molluscan class monoplacaphora, long thought to be extinct, but found in deep oceanic trenches. Since it was first discovered living in 1952, Vema hyalina is the only member of this class which has ever been found in water shallow enough (about 400 meters) to bring live back to a laboratory to study (Lowenstam, 1978). This region of the Santa Rosa-Cortes Ridge is so far the only area Vema has been confirmed to occur.

c. Potential impacts avoided by deferral of this subarea: Deferral of this subarea will reduce impacts to water quality in the area since no drilling discharges would occur. The principal impacts avoided by this deferral would be to eliminate the possibility of impacts to the benthic community and the fossil limpet immediately around potential platform sites within the only known Vema location.

d. Deferral recommended by: California Coastal Commission.

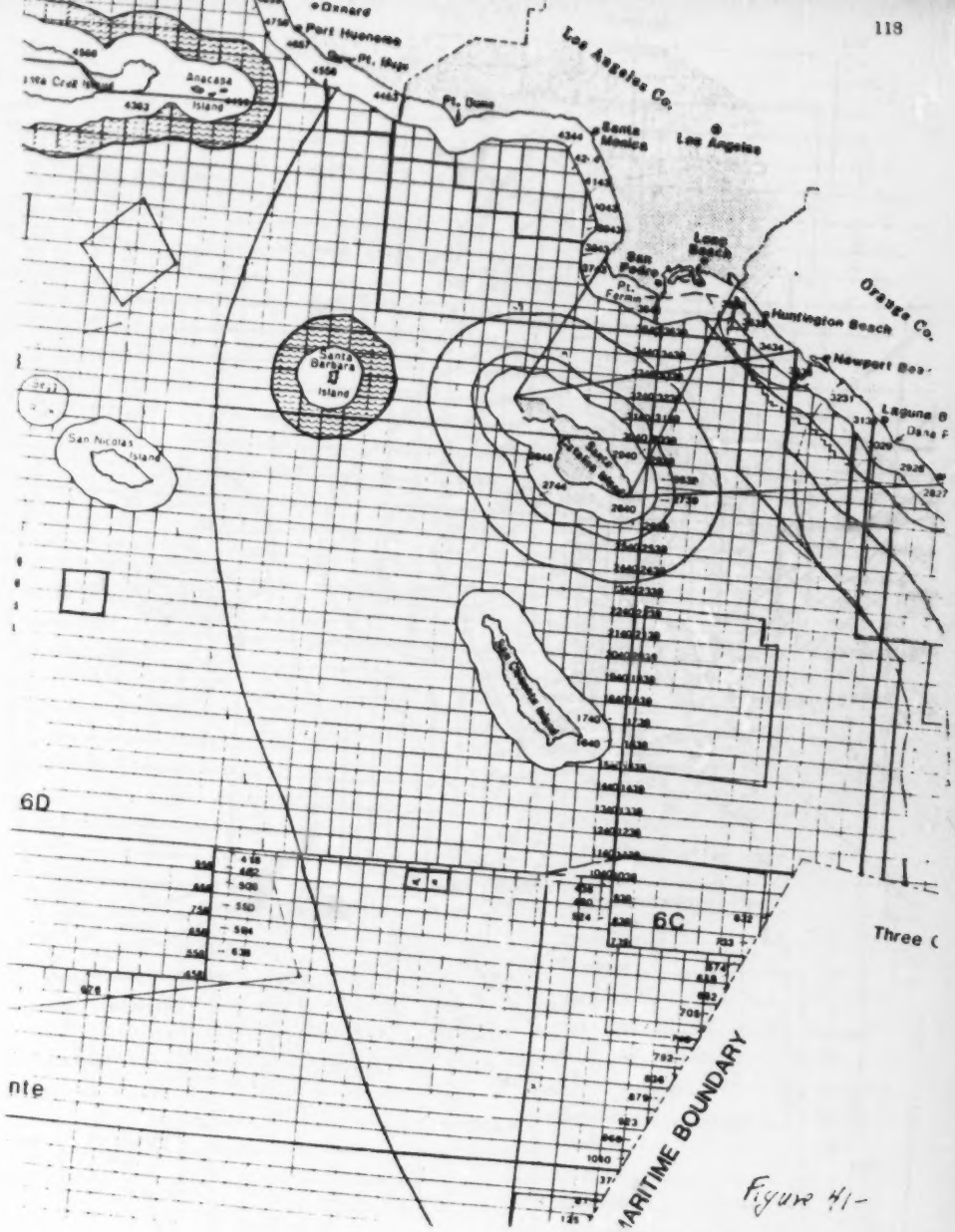


Figure 41-

Southern California

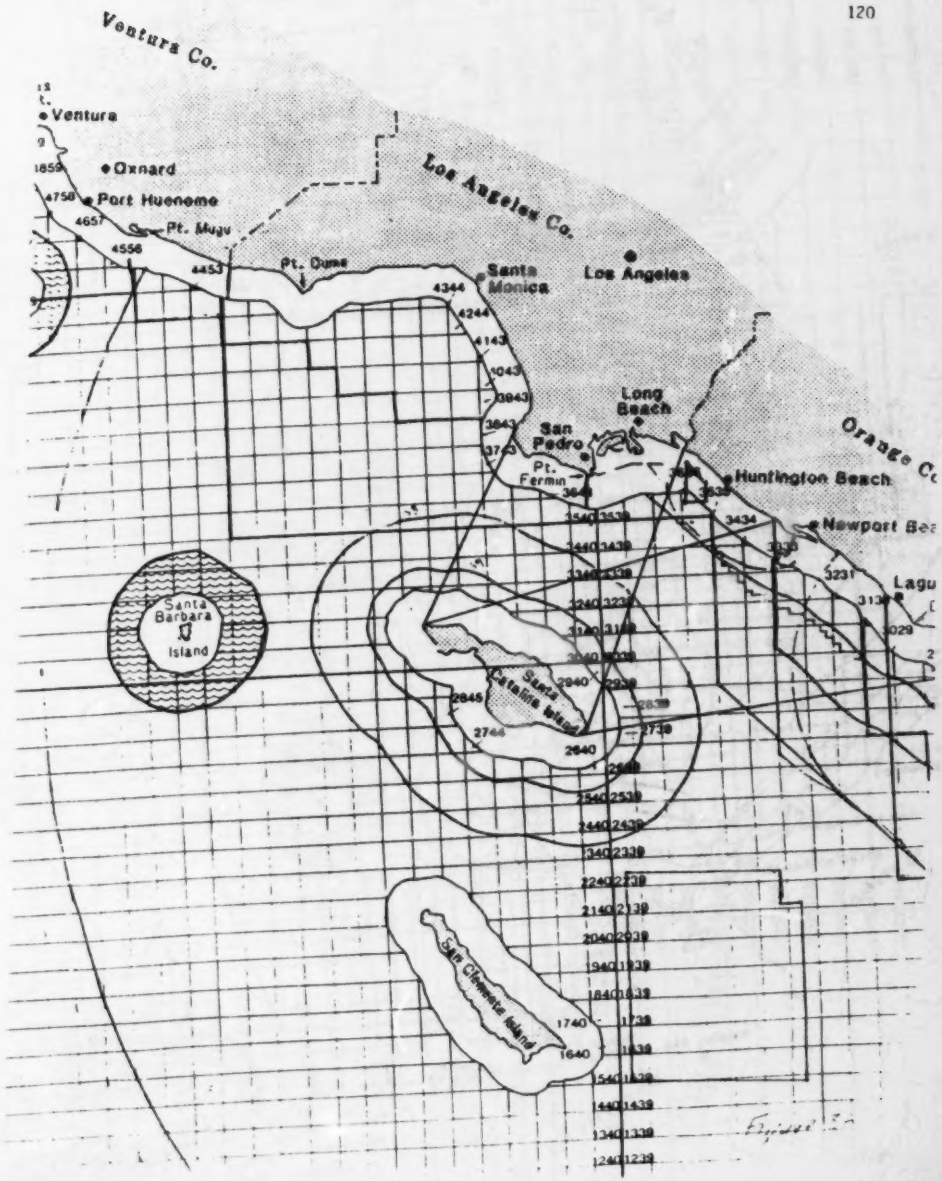
Tracts 12 miles around Catalina Island

a. Geographic Description: This area encompasses 120 whole or partial tracts bordered by the 3-mile State jurisdiction line around Santa Catalina Island and extending 12 miles out around the island (see figure 38-1).

b. Description of the environment: Catalina Island is a very popular tourist spot year round, but particularly in the summer months. Recreational beaches, diving, pleasure boating and sailing, sports fishing, and camping are key attractions. Commercial fisheries including squid are found around the island. Sensitive biological resources abound in the coastal area, and specific areas have been so designated. These included Lover's Point Reserve; Farnsworth Bank Ecological Reserve; the Isthmus; Little Harbor; and Pinnacle Rock. Sensitive biological habitats are found throughout the islands offshore habitats in the rocky intertidal, subtidal and near offshore zones. The aesthetic/visual beauty of the island with its dramatic cliffs and panoramic views are an important reason for the island's appeal.

c. Potential impacts avoided by deferral of this subarea: If this area is deferred, the key potential impacts reduced are: 1) adverse aesthetic/visual effects from the installation of offshore structures and onshore support facilities; 2) possible loss of recreational facilities as the oil and gas industry would require onshore support facilities in the coastal zone; 3) potential oil spills originating from OCS activity resulting in the closure of harbors and beaches (loss of tourist money) and loss of biological resources and commercial fisheries; 4) bottom disturbances to biological habitats from pipeline and platform installations; and 5) air quality degradation due to increased boat traffic and the powering of platforms.

d. Deferral recommended by: State of California, City of Avalon.



Southern California

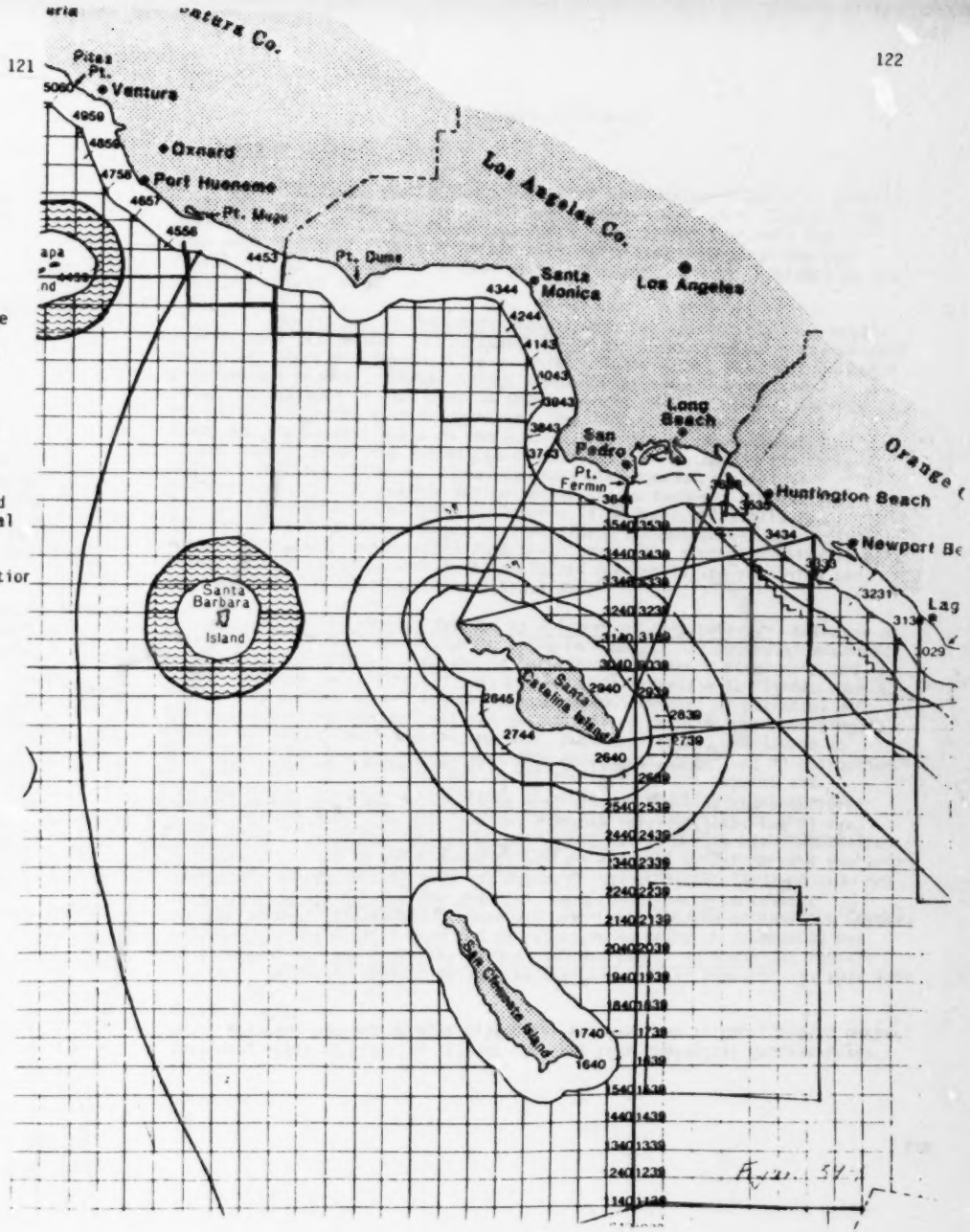
Tracts 6 miles around Catalina Island

a. Geographic Description: This area encompasses 51 whole or partial tracts bordered by the 3-mile jurisdiction line around Catalina Island and extending 6 miles out around the island (see figure 39-1).

b. Description of the environment: Catalina Island is a very popular tourist spot year round, but particularly in the summer months. Recreational beaches, diving, pleasure boating and sailing, sports fishing, and camping are key attractions. Commercial fisheries including squid are found around the island. Sensitive biological habitats are found throughout the island in the rocky intertidal, subtidal and near offshore zones. The aesthetic/visual beauty of the island with its dramatic cliffs and panaramic views are an important reason for the island's appeal.

c. Potential impacts avoided by deferral of this subarea: If this area is deferred, the key potential impacts reduced are: 1) adverse aesthetic/visual effects from installation of offshore structures and onshore support facilities; 2) possible loss of recreational facilities as the oil and gas industry would require onshore facilities in the coastal zone; 3) potential oil spills originating from OCS activity resulting in impacts on biological resources and commercial fisheries; 4) bottom disturbances to biological habitats from pipeline and platform installations; and 5) air quality degradation due to increased boat traffic and the powering of platforms.

d. Deferral recommended by: California Senate, Greenpeace, California Coastal Commission, Natural Resource Defense Council, Monterey County, California Department of Justice.



Southern California

Tracts between South Orange County and Catalina Island

a. Geographic description: This area consists 80 whole or partial blocks between Santa Catalina Island and the southern half of Orange County. This area is bounded by the 3-mile State jurisdiction line on the landward side of Catalina Island and along the Orange County coast from just north of Newport Beach to the San Diego County line. Catalina Island is located 22 miles off the coast of Los Angeles (see Figure 33-1).

b. Description of the environment: Catalina Island is a very popular tourist spot yearround, but particularly in the summer months. Recreational beaches, pleasure boating and sailing, and camping are key attractions. The portion of Orange County delineated above is also very important for recreational resources such as beaches, boating, and sport fishing. Part of the attraction to tourists for both Catalina and this part of Orange County is the high aesthetic/visual beauty of these shorelines. These coastal areas are quite dramatic with cliffs along the shore line and relatively few changes created by man. Additional information on the Orange County resources are described in those subarea sections.

Recreational boating and sportsfishing occur extensively throughout the area, with Orange County marinas located at Huntington Harbour, Newport Beach, and Dana Point Harbour, with approximately six million participation days annually. The visual resources of the area are considered very important, contributing to the recreational appeal of the area. The 16 mile stretch of coast from Newport Beach to Dana Point is one of the most scenic coastal areas of Southern California.

This area is adjacent to several coastal areas that are biologically sensitive or isolated, some of which have been given special designations as areas of special biological significance (ASBS) or marine life refuges (MLR) and include: Newport Beach MLR and ASBS; Laguna Beach MLR; South Laguna Beach MLR; and Niguel MLR. The rocky intertidal substrate environment between Newport Beach and Dana Point contains unusually rich or diverse biotic assemblages, and are relatively undisturbed: the Irvine coast including Treasure Cove; Cresent Bay; Salt Creek Area; and Newport Bay.

Commercial fisheries are located off Orange County in the vicinity of Newport and Laguna Beaches. These fisheres include squid, anchovy, and various shellfish.

There are important offshore biological resources associated with the California Channel Islands including Catalina Island and the nearshore area. These resources include fish resources (some commercial), both pelagic and shallow rocky bottom fish, marine mammals (cetaceans and pinnipeds) and seabirds (both migratory and local), kelp beds, biological communities associated with rocky bottoms, rocky intertidal zones, and estuaries and embayments (such as Newport Bay, Avalon Bay).

Defined areas of biological significance in this area are: Bolsa Chica Ecological Reserve; Upper Newport Bay Ecological Reserve; Laguna and South Laguna Beach MLR; Niguel MLR; Dana Point MLR; Newport Beach MLR and ASBS; and

following areas on Catalina Island: Abalone Cove Ecological Reserve-Lover's Point Reserve; Farnsworth Bank Ecological Reserve; the Isthmus; Little Harbor; Pinnacle Rock.

c. Potential impacts avoided by deferral of this subarea: If this area is deferred, the key potential impacts avoided area: 1) potential adverse aesthetic/visual effects from the installation of offshore structures and onshore support facilities; 2) possible loss of recreation beaches and related facilities as the oil and gas industry would require onshore support facilities in the coastal zone; 3) potential oil spills originating from OCS activity resulting in the closure of beaches (loss of tourist money) and loss of biological resources and commercial fisheries; 4) bottom disturbances to biological habitats from pipeline and platform installations; and 5) air quality degradation due to increased boat traffic and platform operations.

d. Deferral recommended by: City of Laguna Beach

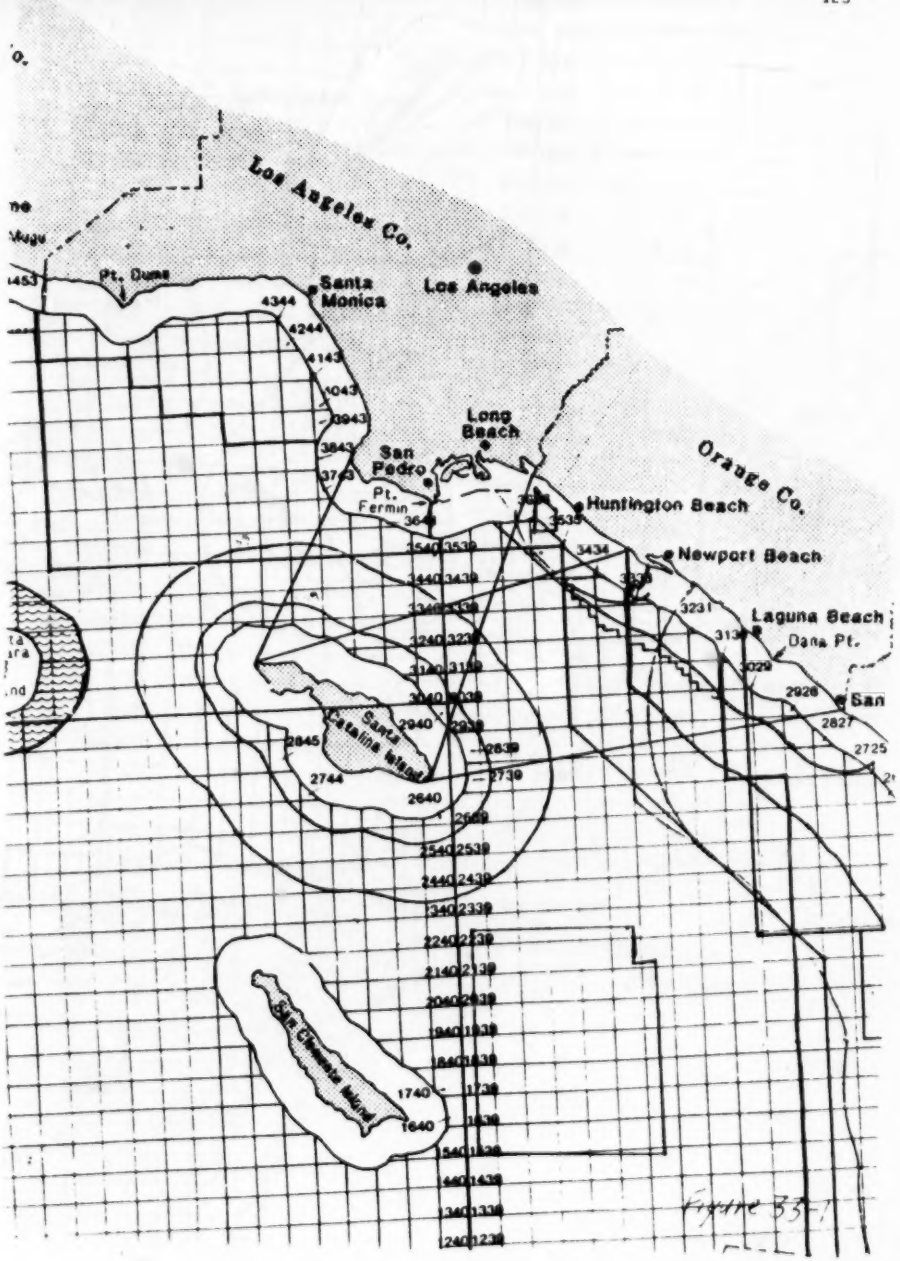


Figure 33-1

Southern California

Shoreward of Catalina Island

a. Geographic description: This area encompasses 47 whole or partial tracts between Santa Catalina Island and southern Los Angeles County. The area is defined by a line drawn from Point Palos Verdes to Land's End (the western tip of Catalina) on the west and a line drawn from the Los Angeles/Orange County line to Seal Rock (the eastern tip of Catalina) on the east (see Figure 36-1).

b. Description of the environment: Catalina Island is a very popular tourist spot year round, but particularly in the summer months. Recreational activities important for Catalina as well as Palos Verdes and the Long Beach area include beaches, sportsfishing, scuba diving, pleasure boating. Commercial fishing is important in this area with squid, anchovy, various shellfish, and other fish being taken. The Ports of Los Angeles/Long Beach are the busiest ports on the U.S. west coast and among the busiest in the world. Sensitive biological communities are located in the rocky coastal areas and offshore. Specific areas with special biological designations are: Pt. Fermin Marine Refuge (Palos Verdes); Abalone Cove Ecological Reserve (Palos Verdes); Lover's Point Reserve (Catalina); Farnsworth Bank Ecological Preserve (Catalina); Isthmus (Catalina); Little Harbor (Catalina); and Pinnacle Rock (Catalina). The aesthetic value/visual beauty of both Catalina and the Palos Verdes Penninsula are very high and help make this an important recreational area.

c. Potential impacts avoided by deferral of this subarea: Deferral of this area will reduce the following possible impacts: 1) potential adverse aesthetic/visual effects from the installation of offshore structures and onshore support facilities; 2) possible loss of recreation facilities such as beaches and marinas to oil and gas industry requirements; 3) potential oil spills originating from OCS oil and gas activities in this area resulting in closure of recreational beaches, marinas, port facilities, and damage to biological resources including commercial and sports fisheries; 4) disruption of marine vessel traffic into and out of the ports of Los Angeles and Long Beach due to possible collisions of vessels with offshore platforms and increased traffic congestion requiring possible rerouting of the vessel lanes and precautionary areas; 5) bottom disturbances to biological habitats from pipeline and platform installations; and 6) air quality degradation due to increased boat traffic and platform operations.

d. Deferral recommended by: State of California, City of Laguna Beach

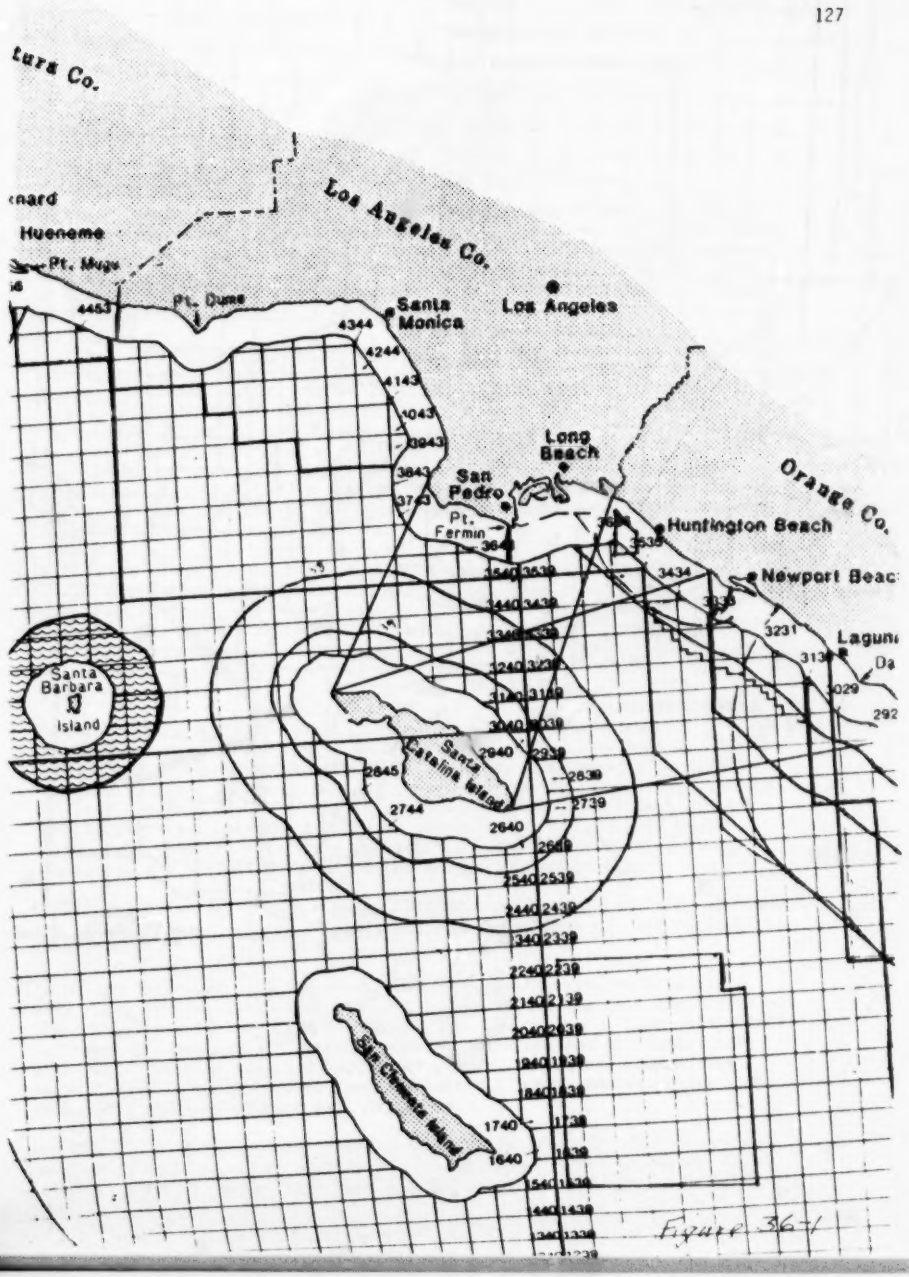


Figure 36-1

Southern California

Defer a buffer 12 miles wide between Newport Beach and the Mexican Border

a. Geographic description: This subarea deferral would remove 138 complete and partial tracts from the proposed planning area. These tracts are located from three to 27 miles offshore from Dana Point in the north to the U.S./Mexico border in the south (see figure 26-1).

b. Description of the environment: The San Diego county shoreline plays a significant role in local and regional economics through recreational beach use and tourism. It is estimated that recreational beach use in San Diego county is in excees of 20 million recreationists per year, with an estimated value in excess of $122 million in 1980. Tourism is also significant in that it was estimated to be excess of $557 million in 1980.

The U.S. Navy, Air Force, and Marines utilize the San Diego harbour area and large portions of the nearshore area for training exercises and testing of equipment and personnel. Significant biological areas; wetlands, estuaries, rocky intertidal areas, exist along the coast which could suffer significant impacts should an oil spill occur and contact the coast. Endangered species are known to utilize or inhabit the wetlands and estuaries along this coast. These species could also suffer significant impacts should an oil spill occur and contact the coast.

c. Potential impacts avoided by deferral of this subarea: Deferral of this subarea would reduce the potential local impact to visual resources as no platform would be situated in the subarea. This in turn would reduce the potential impacts to recreation and tourism. Deferral of this subarea would provide protection for a significant number of resources by allowing additional time for weathering, diversion and clean-up of an oil spill should such an event occur. Specific resources provided protection would be: 1) Recreation resources, including tourism and visual resources; 2) Military use areas; 3) Estuaries and wetlands; 4) Biologically significant areas; 5) Rocky intertidal areas; and 6) Endangered and threatened species.

d. Deferral recommended by: California Senate

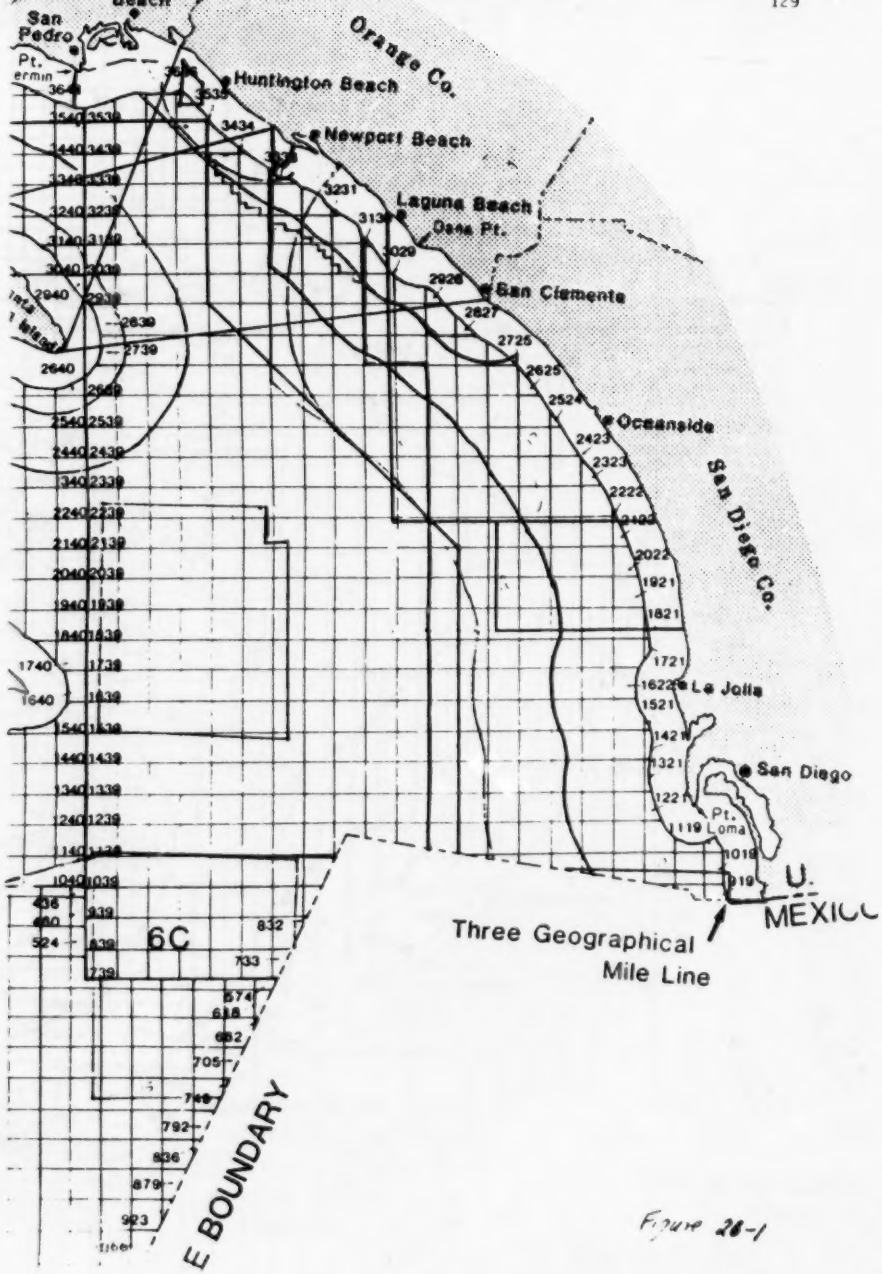


Figure 28-1

Southern California

Defer a buffer 20 miles wide between Newport Beach and the Mexican border:

a. Geographic description: This subarea deferral would remove approximately 165 complete and partial tracts from the proposed planning area. These tracts are located within a 20 mile wide stretch of ocean from Newport Beach to the Mexican border (see figure 28-1).

b. Description of the environment: The San Diego County shoreline plays a significant role in local and regional economics through recreational beach use and tourism. It is estimated that recreational beach use in San Diego County is in excess of 20 million recreationists per year, with an estimated value in excess of $122 million in 1980. Tourism is also significant in that it was estimated to be in excess of $577 million in 1980.

The U.S. Navy, Air Force, and Marines utilize the San Diego harbour area and large portions of the nearshore area for training exercises and testing of equipment and personnel. Significant biological areas; wetlands, estuaries, rocky intertidal areas, exist along the coast which could suffer significant impacts should an oil spill occur and contact the coast. Endangered species are known to utilize or inhabit the wetlands and estuaries along this coast. These species could also suffer significant impacts should an oil spill occur and contact the coast.

c. Potential impacts avoided by deferral of this subarea: Deferral of this subarea would reduce the potential local impact to visual resources as no platform would be situated in the deferral subarea. This in turn would reduce the potential impacts to recreation and tourism. Deferral of this subarea would provide protection for a significant number of resources by allowing additional time for weathering, diversion and clean-up of an oil spill should such an event occur. Specific resources provided protection would be: 1) Recreation resources, including tourism and visual resources; 2) Military use areas; 3) Estuaries and wetlands; 4) Biologically significant areas; 5) Rocky intertidal areas; and 6) Endangered and threatened species.

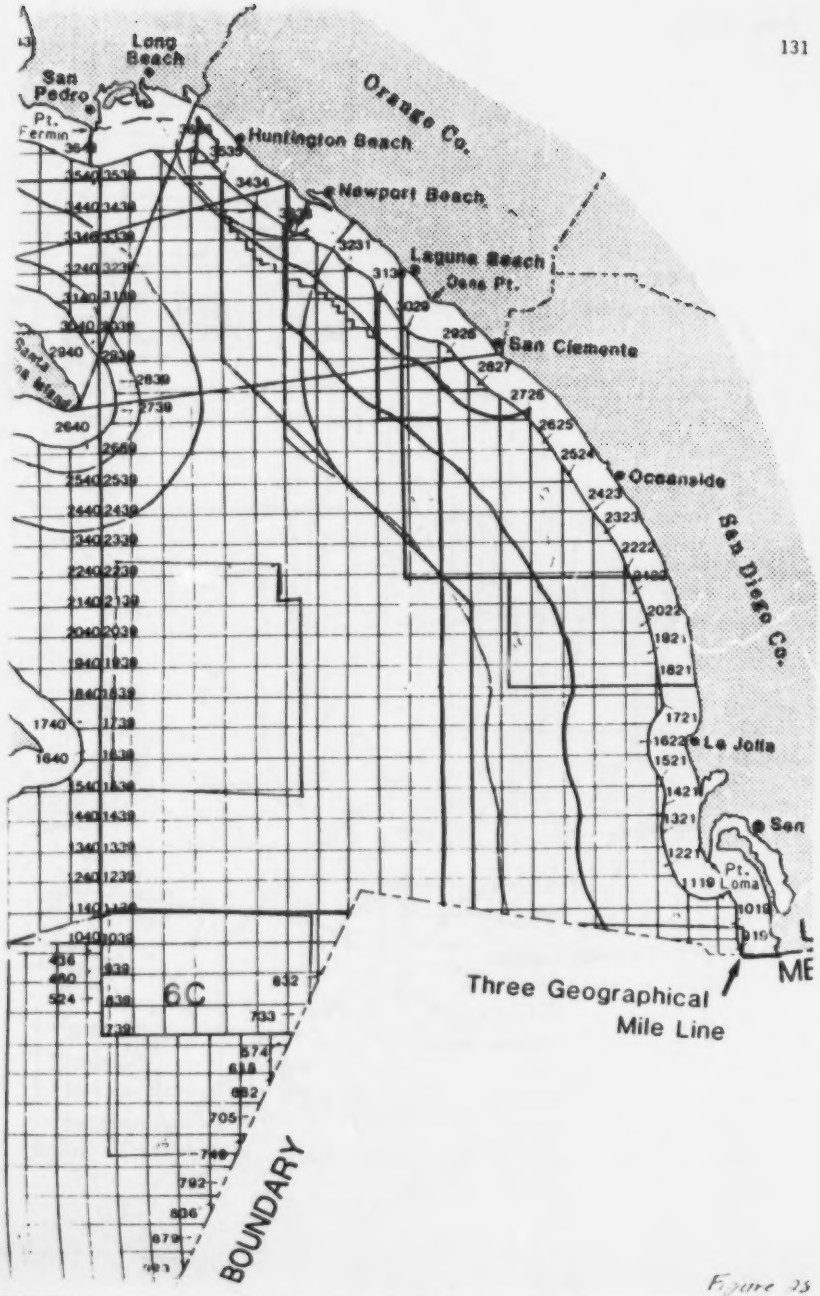


Figure 25

Southern California

Southern Orange County Coast

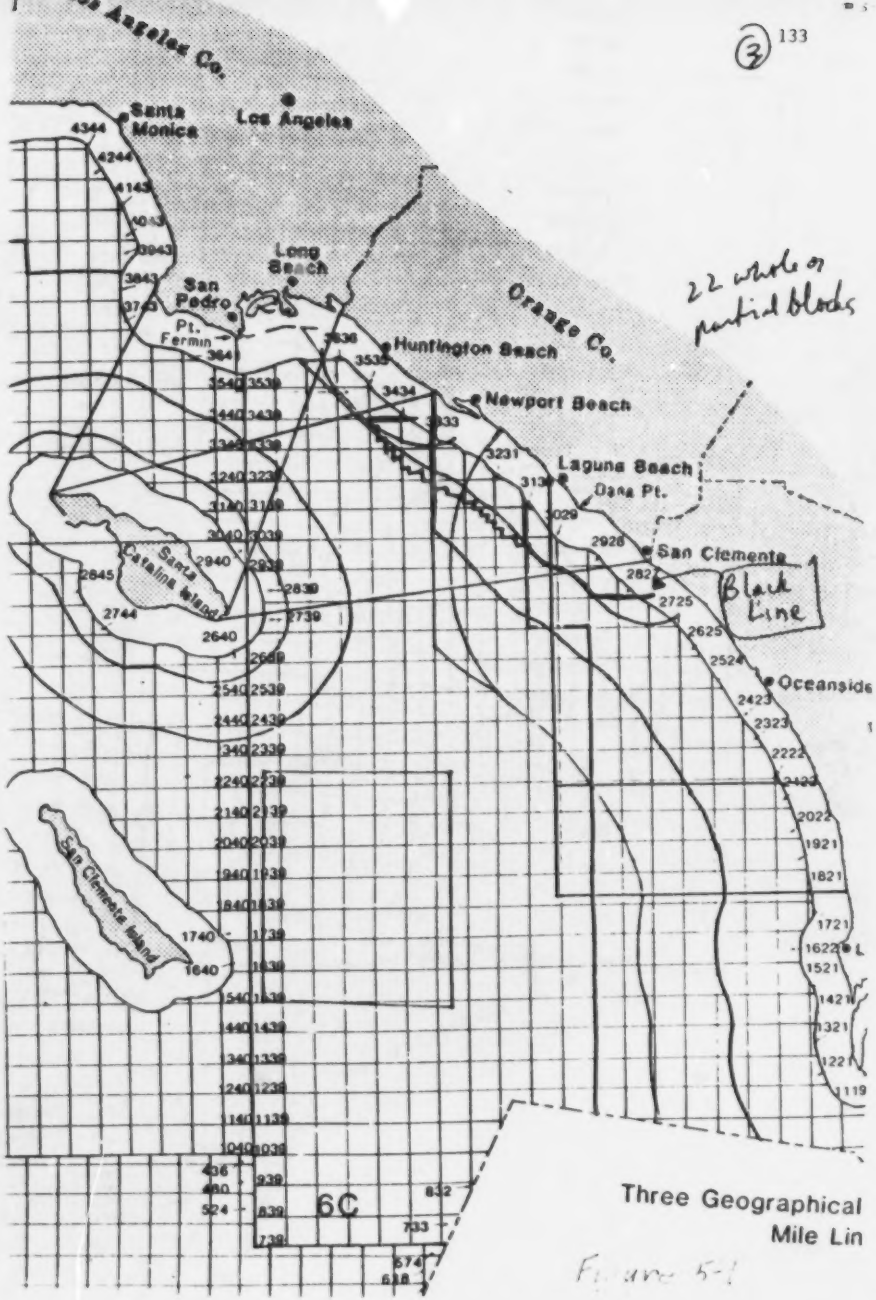
a. Geographic description: The southern Orange County coast subarea deferral would remove approximately 19 complete and partial blocks from the offering area (see figure 5-1). The subarea is bounded on the north by the Santa Ana River, and on the south by the Orange County/San Diego County line.

b. Description of the environment: The southern Orange County coastline plays a significant role in local and regional economics. Extensive recreational beach use and tourism are significant contributors to the county. The 1980 recreational attendance at Orange County area beaches was over 45 million, with tourism valued at approximately $750 million in 1979. The Orange County area represents about 10 percent of the total Southern California tourism industry, and is second only to Santa Monica Bay for recreational usage.

Recreational boating and sportfishing occur extensively throughout the area, with Orange County marinas located at Huntington Harbour, Newport Beach, and Dana Point Harbour, with approximately 6 million participation days annually. The visual resources of the area are considered very important, contributing to the recreational appeal of the area. The 16 mile stretch of coast from Newport Beach to Dana Point is one of the most scenic coastal areas of Southern California.

The southern Orange County coastline contains several coastal areas that are biologically sensitive or isolated, some of which have been given special designations. These areas are listed below. The rocky intertidal substrate environment between Newport Beach and Dana Point contains the following areas that are geographically isolated from similar environments by 32 to 64 miles, contain unusually rich or diverse biotic assemblages, and are relatively undisturbed: the Irvine Coast including Treasure Cove; Crescent Bay; Salt Creek area; and Newport Bay. The following areas have been given designations as areas of special biological significance (ASBS) or marine life refuges (MLR): Newport Beach MLR and ASBS; Irvine Coast MLR and ASBS; Laguna Beach MLR; South Laguna Beach MLR; and Niguel MLR.

c. Potential impacts avoided by deferral of this subarea: Deferral of this subarea would reduce the potential local impacts to recreation, tourism and visual resources since no platform would be located within 5 to 7 miles of the coast. Deferral of this subarea would also reduce the potential impacts from oil spills, as any spills that occur from oil exploration or development activities would originate further offshore. This would allow greater time for the mobilization of cleanup efforts as well as decrease the toxicity and quantity of the spilled oil (through evaporation, dispersion, sinking, weathering, and other natural processes), before possible shoreline contact. The resources that may be affected by oil spills, should one occur, are fish resources, commercial fisheries, areas of specific biological significance, estuaries and wetlands. intertidal and subtidal benthos, recreational resources, seabirds, and water quality.



Southern California

Defer a 6-mile buffer zone off Huntington Beach

a. Geographic description: This area consists of 12 partial tracts defined by an arc six miles from the City of Huntington Beach in northern Orange County. The northern limit of this area is offshore of the Los Angeles/Orange County line. The southern limit is offshore of New port Beach, the nearshore limit is the state 3-mile jurisdictional line (see figure 30-1).

b. Description of the environment: Recreational beach usage of this portion of the Orange County coast is very significant. Recreational boating and sportfishing occur extensively in the area. Marinas are located in Huntington Harbour and Newport Beach. There are commercial fisheries in the Newport Beach area including shellfish, anchovy, and squid. Important biological resources are located throughout the coastal area adjacent to this area and include the Newport Beach Marine Life Refuge (MLR) and area of special biological significance (ASBS), and the Irvine Coast MLR and ASBS.

c. Potential impacts avoided by deferral of this subarea: Potential impacts would be reduced or eliminated in several resource categories if this subarea is deferred. A buffer zone would be created affording additional coastal protection from potential oil spills, thus allowing greater time to mobilize oil spill cleanup efforts; allowing greater natural dissipation, weathering, and evaporation of oil (decreasing quantity) before potential coastline contact; and reducing potential adverse visual effects in an area important for its aesthetic value (especially the coastal area near Newport Beach). Additional resource categories that will have potential impacts reduced because of the above area: commercial fisheries, fish resources, areas of special biological significance, interidal and subtidal benthos, wetlands, estuaries, recreation and tourism, cultural resources, and the coastal economy.

d. Deferral recommended by: State of California, City of Huntington Beach.

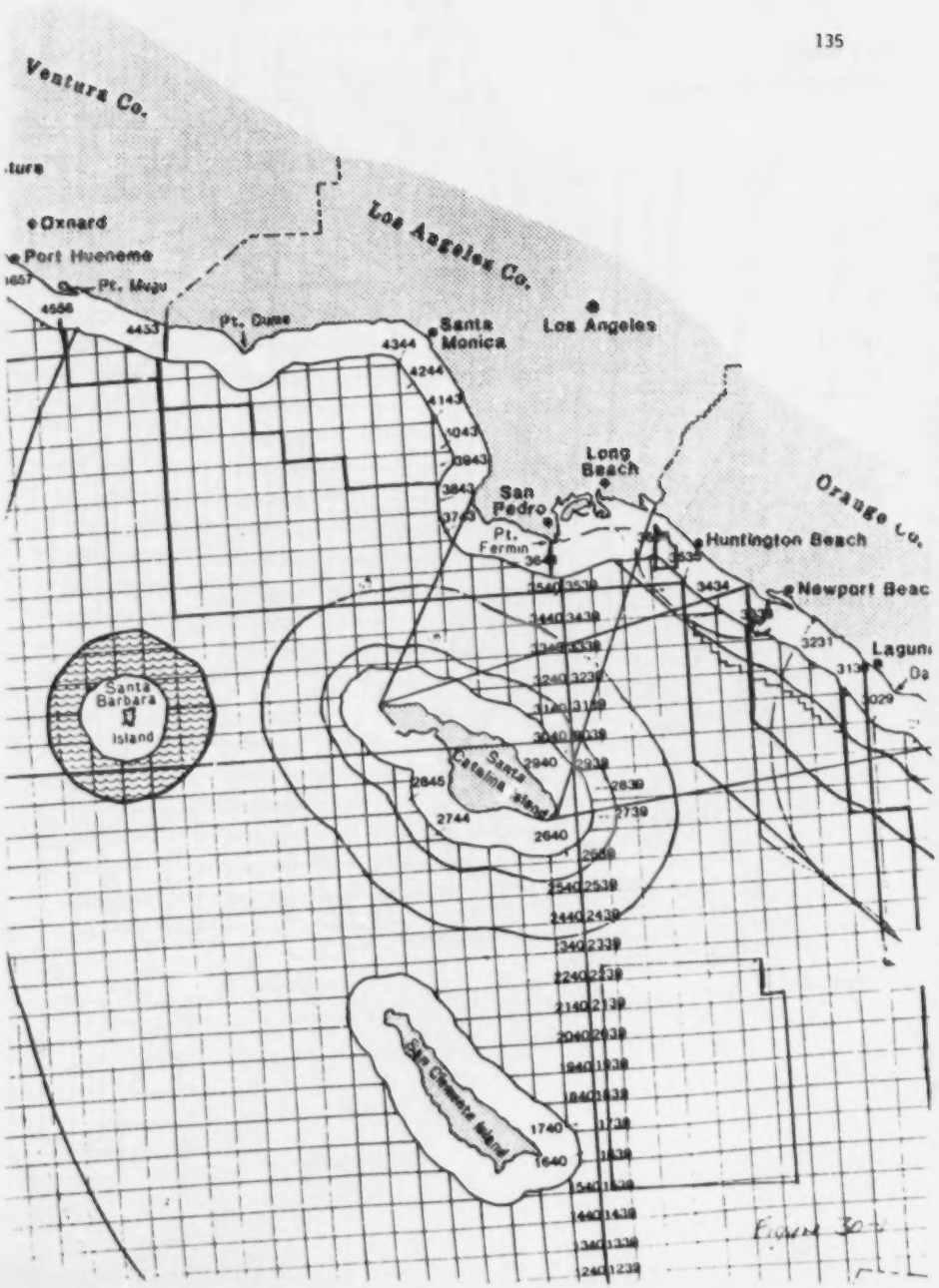


Figure 32-

Southern California

Area within 6 1/2 miles of Orange County Coastline

a. Geographic description: This area consists of 37 partial tracts running along the Orange County coast beginning at the L.A. County line near Long Beach in the north to the San Diego County line near San Clemente in the south. The area is bounded by the 3-mile State jurisdiction line on the coastal side and extends 6 1/2 miles out to sea (see figure 32-1).

b. Description of the environment: Recreational beach use of the Orange County coastline is very significant to the economies of the local coastal communities as well as the State. The 1980 recreation attendance at Orange County area beaches was over 45 million, with tourism valued at approximately $750 million in 1979. The Orange County area represents about 10 percent of the total Southern California tourism industry, and is second only to Santa Monica Bay for recreational beach usage.

Recreational boating and sportsfishing occur extensively throughout the area, with Orange County marinas located at Huntington Harbour, Newport Beach, and Dana Point Harbour, with approximately six million participation days annually. The visual resources of the area are considered very important, contributing to the recreational appeal fo the area. The 16 mile stretch of coast from Newport Beach to Dana Point is one of the most scenic coastal areas of Southern California.

This area is adjacent to several coastal areas that are biologically sensitive or isolated, some of which have been given special designations as areas of special biological significance (ASBS) or marine life refuges (MLR) and include: Newport Beach MLR and ASBS; Laguna Beach MLR; South Laguna Beach MLR; and Niguel MLR. The rocky intertidal substrate environments between Newport Beach and Dana Point contains unusually rich or diverse biotic assemblages, and are relatively undisturbed: including the Irvine coast Treasure Cove; Cresent Bay; Salt Creek Area; and Newport Bay.

Commercial fisheries are located off Orange County in the vicinity of Newport and Laguna Beaches. These fisheres include squid, anchovy, and various shellfish.

c. Potential impacts avoided by deferral of this subarea: Potential impacts to several resource categories will be reduced. These include recreational resources where additional protecton is provided with the deferral, eliminating the possibility of nearshore platform placement and related activities and potential adverse effects. The biological resources in the coastal vicinity of this area will also be afforded additional protection, as oil spills that may occur from development or exploratory drilling would originate further offshore. This would decrease potential oil spill impacts as more time would exist before possible coastline contact, allowing greater mobilization of cleanup efforts and increased evaporation, dispersion, and sinking.

d. Deferral recommended by: State of California

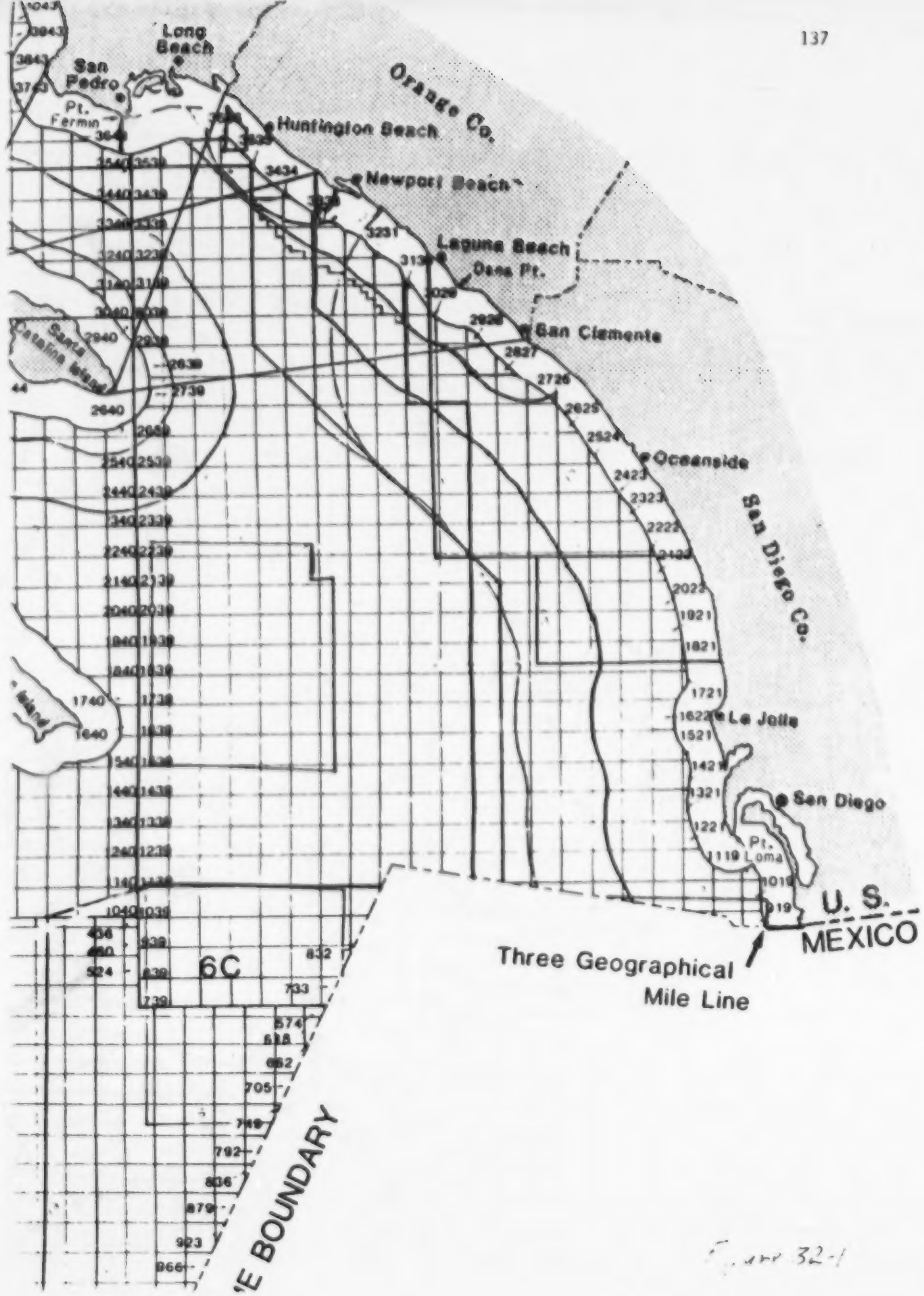


Figure 32-1

Southern California

All Nearshore tracts off southern Orange County

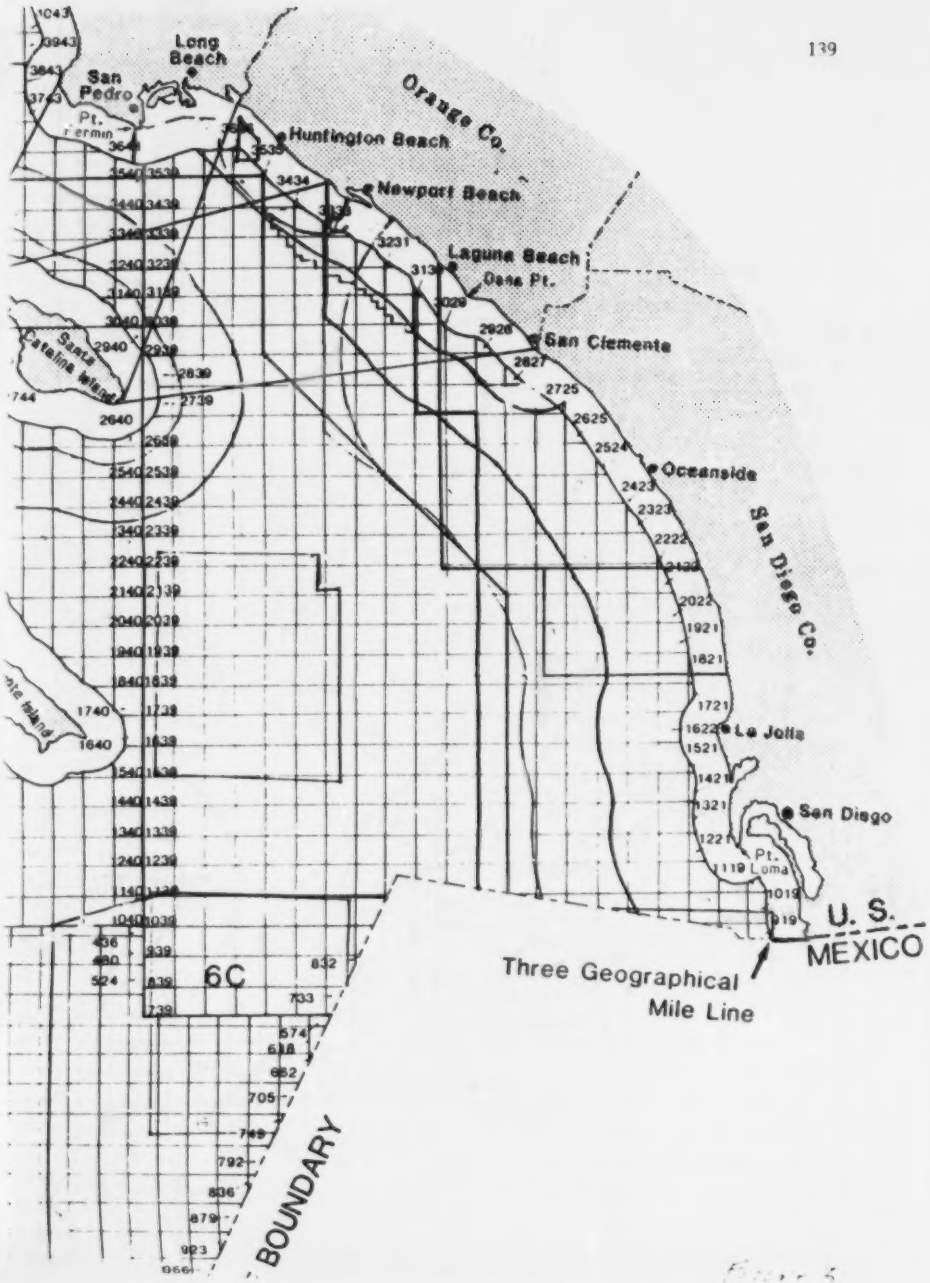
a. Geographic description: This area consists of tracts beginning 3 miles offshore extending 6 1/2 miles offshore from off Newport Beach in the north (central Orange County) to the Orange/San Diego County line in the south. The area is made up of 22 whole or partial blocks (see figure 31-1).

b. Description of the environment: Recreational beach use of the Orange County coastline is very significant to the economies of the local coastal communities as well as of the State. The 1980 recreational attendance at Orange County beaches was over 45 million, with tourism valued at approximately $750 million in 1979. The Orange County area represents about 10 percent of the total Southern California tourism industry, and is second only to Santa Monica Bay for recreational appeal of the area. The 16 mile stretch of coast from Newport Beach to Dana Point is one of the most scenic coastal areas of Southern California.

This area is adjacent to several coastal areas that are biologically sensitive or isolated, some of which have been given special designations as areas of special biological significance (ASBS) or marine life refuges (MLR) and include: Newport Beach MLR and ASBS; Laguna Beach MLR; South Laguna Beach MLR; and Niguel MLR. The rocky intertidal substrate environments between Newport Beach and Dana Point contains unusually rich or diverse biotic assemblages, and are relatively undisturbed.

c. Potential impacts avoided by deferral of this subareas: Deferral of these blocks from the offering eliminates the possibility of platform placement in the nearshore area, reducing potential adverse visual effects in an area heavily used for recreation. Deferrig these blocks would also reduce the potential impacts from oil spills, as any spills that may occur from oil exploraton or development activities would originate further offshore. This would allow greater time for the mobilization of cleanup efforts as well as decrease the toxicity and quantity of the spilled oil (through evaporation, dispersion, sinking, weathering, and other natural processes) before possible shore line contact. The resources that may be affected by oil spills, should one occur, are fish resources, commercial fisheries, areas of special biological significance, estuaries and wetlands, intertidal and subtidal benthos, recreational resources, seabirds, and water quality.

d. Deferral recommended by: California Department of Justice, City of San Diego.



Southern California

Anaheim Bay/Los Angeles-Long Beach Precautionary Area

a. Geographic description: This area represents the portion of the Los Angeles/Long Beach (L.A./L.B.) Vessel Traffic Precautionary Area in Federal waters, totalling ten partial blocks (see Figure 7-1). The area is just south of the Port of L.A./L.B. and bounded on the north by the three-mile State jurisdiction line and extendig to below Pt. Fermin (Palos Verdes Peninsula) on the west and below Seal Beach (near Anaheim Bay) on the east.

It is unlikely that the Coast Guard would permit any surface exploratory drilling operations or permanent platform placement in the Precautionary Area due to the high traffice volume into and out of the Port of L.A./L.B., and the increased risk of vessel accidents the structures would pose.

b. Description of the environment: The L.A./L.B. Precautionary Area is part of the marine vessel routing system controlled by the U.S. Coast Guard and the International Maritime Organization. The area is just below the Port of L.A./L.B., the busiest port on the U.S. West coast, and one of the busiest ports in the world. For calendar year 1982, the Port of L.A. had a total of 9,430 inbound vessel trips, and the Port of L.B. had a total of 10,390 inbound vessel trips (U.S. Army Corps of Engineers, 1984).

Certain biological resources nearby are of specific concern. Palos Verdes peninsula is mostly rocky along the coast and intertidal zone. Sensitive biological communities are found in the rocky intertidal zone. Recognizing this, the Pt. Fermin Marine Refuge was established. Gray whales and other small cetaceans are known to congregate in the area near Pt. Fermin. Anaheim Bay is used extensively by seabirds and other marine animals typically found in coastal estuaries. The Seal Beach National Wildlife Refuge is also nearby and is another important location for biological resources. Anaheim Bay is protected as part of this refuge. There are also important recreational beaches along southern L.A. county and northern Orange County nearby. These include the beaches of Long Beach, Belmont Shores, Seal Beach, Sunset Beach, and Huntington Beach and Harbour.

c. Potential impacts avoided by deferral of this subarea: Reduction in the risk of vessel accidents and congestion in the report area, and potential impacts to coastal biological and recreational resources from possible oil spills, bottom disturbances, noise distrubances, and habitat disruption.

d. Resource potential: In terms of quantity and quality, the geotechnical data available in the proposed deferral area are sufficient to define specific traps throughout the entire area and structural traps have been identified throughout the mapped area.

Strategraphic traps may be present in the western portion of the area.

Possible exploration/discovery trends within or adjacent to the subarea include the Palos Verdes Fault/Beta Anticlinal Discovery Trend which extends northwest through the central part of the area.

e. Deferral recommended by: State of California, California Senate.

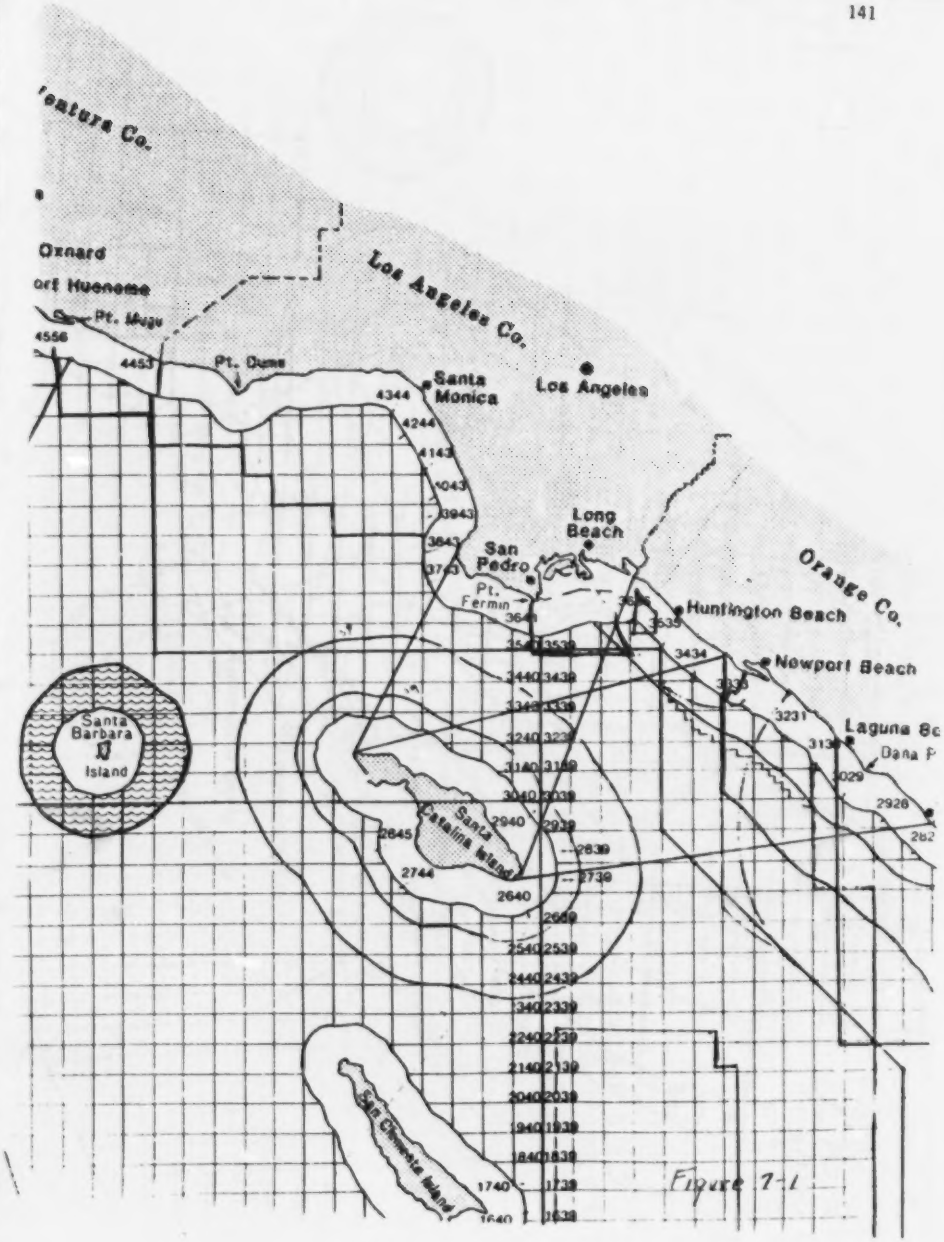


Figure 7-1

Southern California

Palos Verdes

a. Geographic description: The Palos Verdes subarea deferral would remove approximately 25 whole and partial blocks from the offering area (see figure 8-1). The subarea is defined by a line arced 5-7 miles offshore from Flat Rock Point in the north to Point Fermin in the south.

b. Description of the environment: The Palos Verdes peninsula is the most scenic stretch of coastline in Los Angeles county, and is adjacent to the most heavily used recreation area on the Pacific coast, Santa Monica Bay. In addition to its recreation and scenic value, Palos Verdes is also an important rocky intertidal area between Point Mugu on the north and the Irvine coast on the south. Several preserves are to be found on Palos Verdes Peninsula. Palos Verdes Estates Shoreline Preserve and Abalone Cove Ecological Preserve are two such areas.

c. Potential impacts avoided by deferral of this subareas: Deferral of this subarea would reduce the potential local impact to visual resources, recreation and tourism as a result of a platform not being located within 5 to 7 miles of the coast. In addition, it would also reduce the potential impacts from oil spills, as any spills that may occur from oil exploration or development activities would originate further offshore. This would allow greater time for the mobilization of cleanup efforts as well as decrease the toxicity and quantity of the spilled oil (through evaporation, dispersion, sinking, weathering, and other natural processes), before possible shoreline contact.

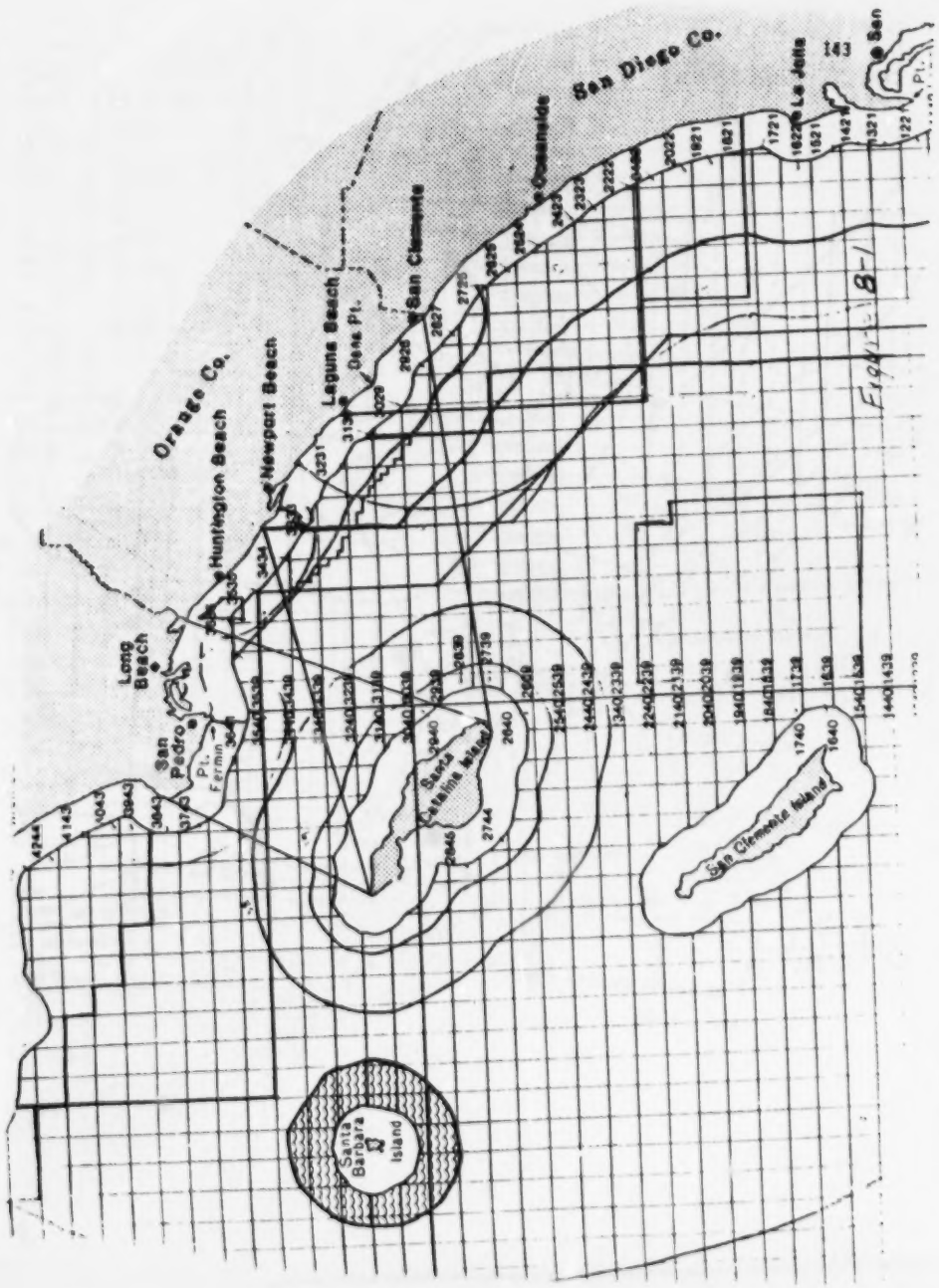


Figure B-1

Southern California

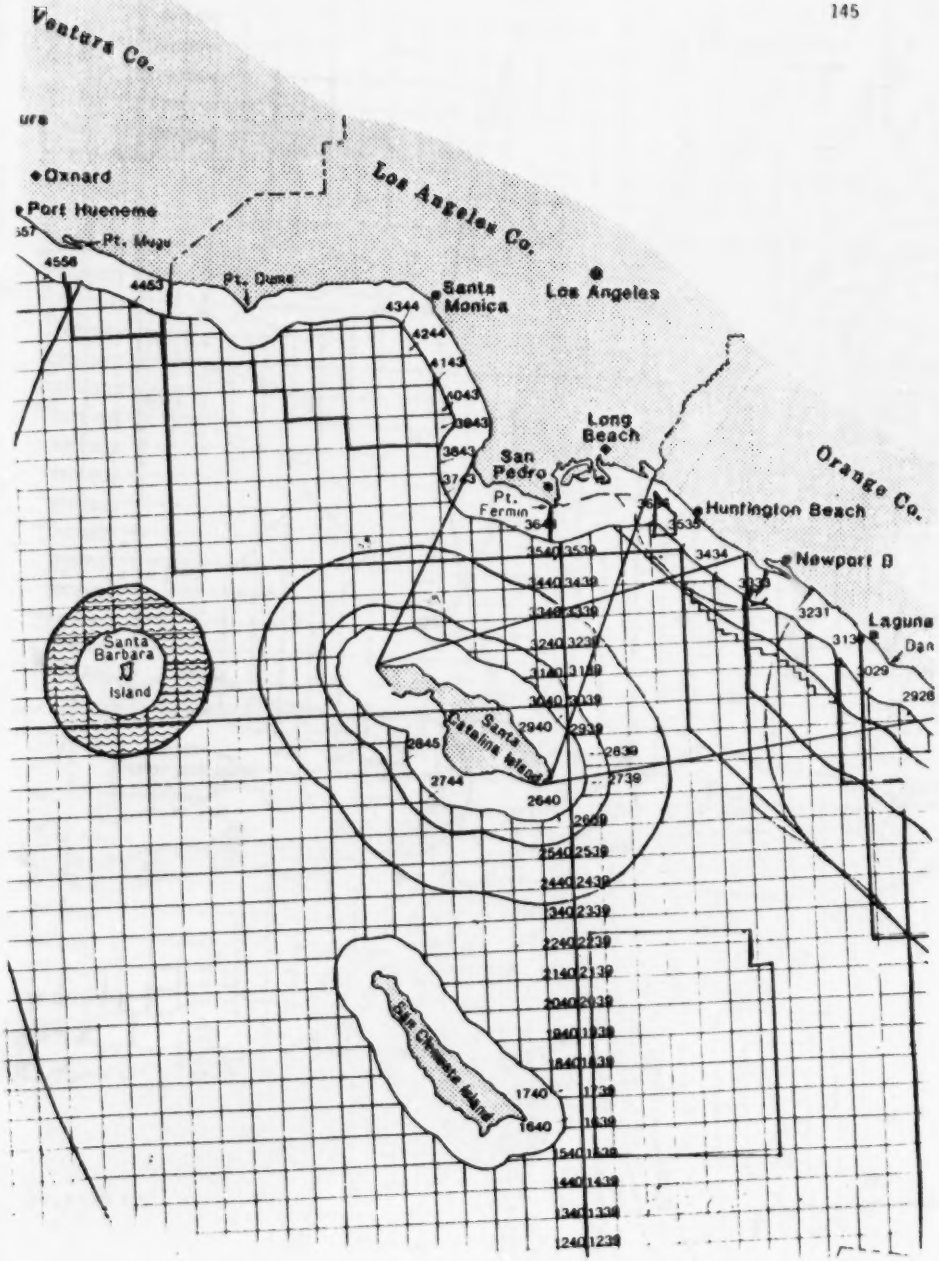
Santa Monica Bay

a. Geographic description: The Santa Monica Bay subarea would remove approximately 40 partial or complete blocks from the offering area (see Figure 35-1). Santa Monica Bay is bounded on the north by Pt. Dume and on the south by the Palos Verdes Peninsula.

b. Description of the environment: Santa Monica Bay is the largest bay in southern California. Pt. Dume to the north and Palos Verdes to the south, both contain sensitive rocky intertidal areas. This stretch of the California coast is one of the most heavily utilized in the Nation. Attendance figures for 1980 indicate the total beach attendance was over 76.4 million. Mugu Lagoon is one of Ventura County's most productive wildlife habitats. A total of 191 species of birds have been sighted here; approximately 10,000 birds winter in the lagoon annually. Several threatened and endangered species occur in relatively large numbers within the bay: 1) gray whales congregate at Pt. Dume; 2) Venice Beach is the nesting area for approximately 15 percent of the endangered least tern population; 3) several hundred brown pelicans concentrate in the bay between September and November; and 4) least terns, light-footed clapper rails, and California black rails, among other species, occur at Mugu Lagoon.

c. Potential impacts avoided by deferral of this subarea: Deferral of this subarea will reduce local impacts to water quality in Santa Monica Bay since no platform and therefore no discharges would occur in the bay. Water quality in the bay will remain degraded due to industrial and municipal sewage discharges, atmospheric fallout of pollutant platform from Santa Monica Bay will eliminate the possibility of impacts to the subtidal benthic community immediately around the platform within the bay. Also, the potential for disruption to the gray whale congregating area off Pt. Dume would be removed. Local impacts to recreation resources (visual) would also be reduced. Deferral of this subarea would provide protection for a significant number of resources in the Santa Monica Bay and north of Pt. Mugu by ensuring additional time for weathering, diversion and cleanup of any exploration or development related oil spill in the event such a spill should occur. Specific resources provided protection would be: 1) intertidal benthos (rocky intertidal areas off Pt. Dume and Palos Verdes); 2) fish resources (anchovy and squid populations in Santa Monica Bay); 3) seabirds (large numbers of migrating birds around Pt. Mugu Estuary and the bay); 4) threatened and endangered species (gray whale congretating area off Pt. Dume, least tern nesting area near Venice Beach, large concentrations of brown pelicans in the bay; 5) estuaries and wetlands (Mugu Lagoon, Malibu River, and Ballona Creek); and 6) recreational resources.

d. Deferral recommended by: State of California, City of Manhattan Beach, Monterey County, City of Santa Monica, Palos Verde Estates, The Whale Center



Southern California

Approximately six whole and partial blocks offshore Point Mugu and the Ventura/Los Angeles County border

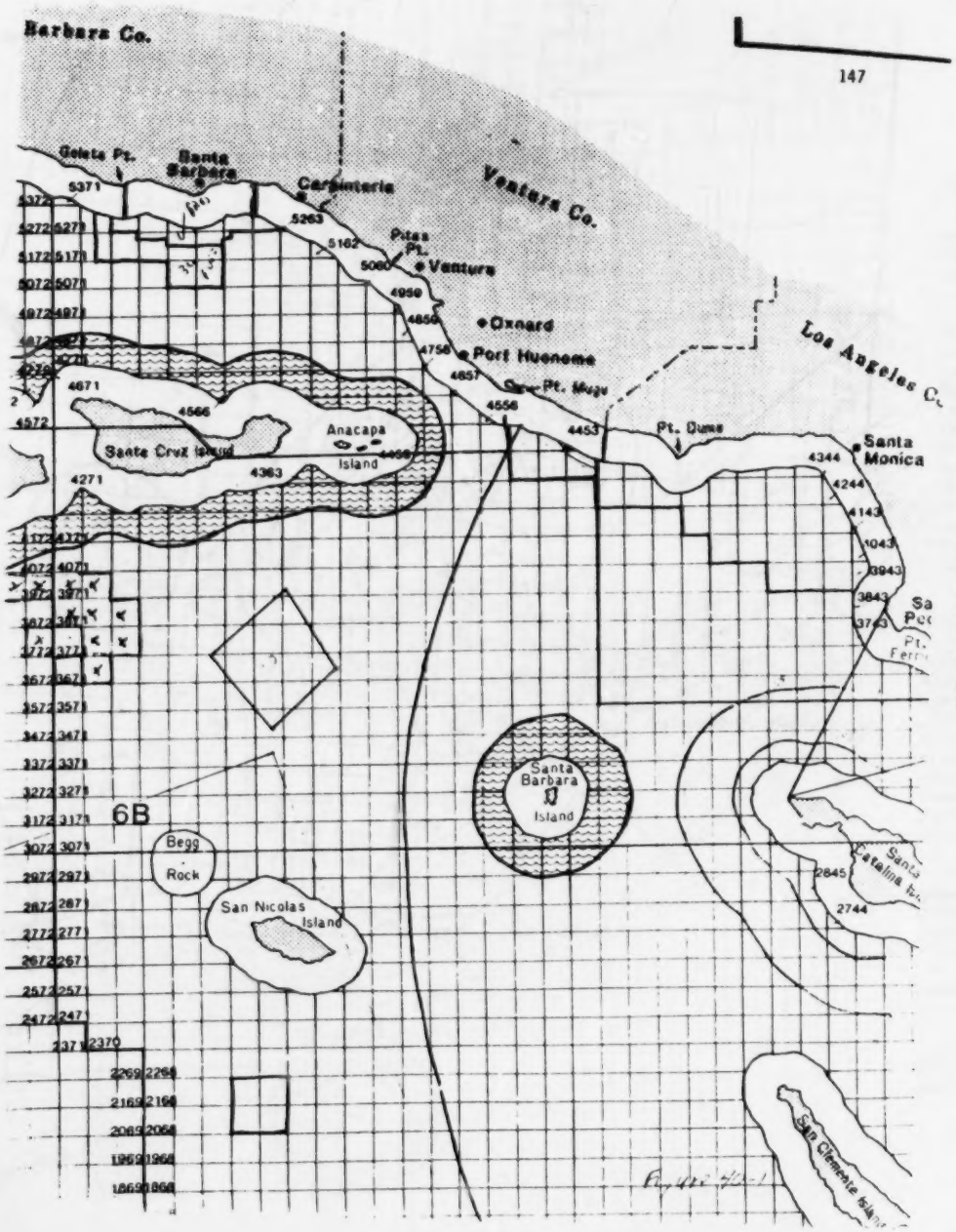
a. Geographic descriptions. This subarea deferral would defer approximately six whole/partial blocks from Point Mugu to the Ventura/Los Angeles County border (see figure 40.1).

b. Description of the environment: Mugu Lagoon is the largest estuary in the Santa Barbara Channel area (see specific subarea deletion for Mugu Lagoon). Contained within the area of the subarea deletion is the Santa Barbara Channel traffic separation scheme.

c. Potential impacts avoided by deferral of this subareas: The deferral of this subarea would allow for additional time for weathering, diversion, and cleanup of an exploration/development related to oil spill in the unlikely event such a spill should occur. This would provide protection to water quality, intertidal benthos, subtidal benthos, fish resources, marine mammals, seabirds, threatened and endangered species, commercial fisheries, and recreational and cultural resources from possible contact with an oil spill.

The subarea deferral would also eliminate localized impacts to water quality and visual resources. It would also eliminate any potential modification of the Santa Barbara Channel traffic separation scheme.

d. Deferral recommended by: California Coastal Commission.



Southern California

Mugu Lagoon

a. Geographical description: The deferral of blocks within a 6 mile zone around Mugu Lagoon would remove approximately 7 partial or complete blocks from the offering area (see figure 9-1). Mugu Lagoon is located approximately 10 miles south of Port Hueneme.

b. Description of the environment: Mugu Lagoon is the largest and most important estuary in the Santa Barbara Channel. It has also been designated by the State of California as an Area of Special Biological Significance. The Lagoon comprises over 1420 acres of marshland, 500 acres of tidal mudflat, and 250 acres of water. This represents 76 to 93 percent of the area's total habitat types. A total of 191 species of birds have been sited within the lagoon; with approximately 10,000 birds wintering in the lagoon annually. Several threatened and endangered species: least terns, light-footed clapper rails and California black rails occur at the lagoon.

c. Potential impacts avoided by deferral of this subarea: The deferral of this subarea would allow for additional time for weathering, diversion and cleanup of an exploration or development related oil spill in the unlikely event such a spill should occur. This would provide protection to water quality, intertidal benthos, subtidal benthos, fish resources, marine mammals, seabirds, threatened and endangered species, commercial fisheries, and recreational and cultural resources from possible contact with an oil spill.

The alternative would also eliminate any exploration or development within the deleted area, thereby, eliminating local impacts to water quality and visual resources.

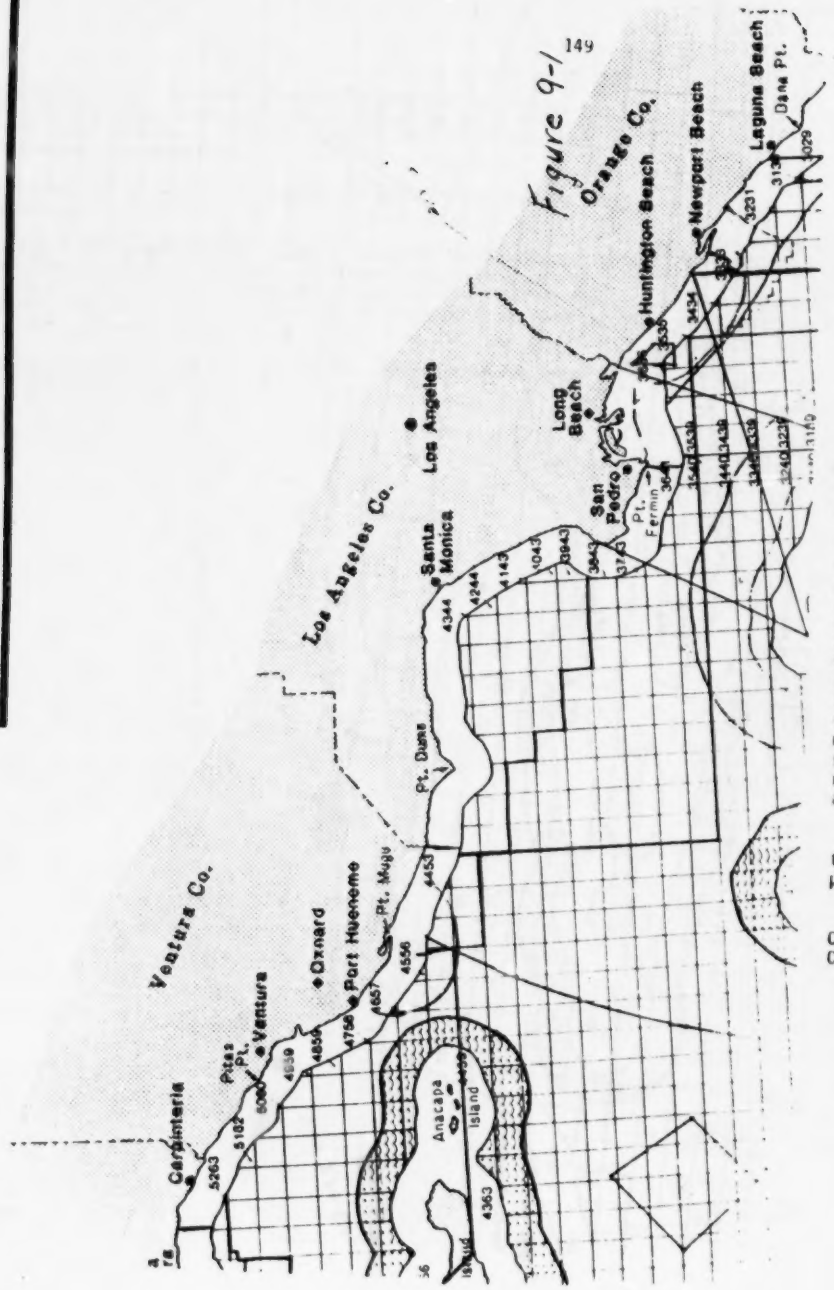


Figure 9-1

Southern California

Santa Barbara Channel

a. Geographic description: This subarea proposed for deferral includes all tracts (276 entire or partial) within the "Santa Barbara Channel" subarea defined for Sale 80 (Minerals Management Service, 1983). These tracts include those of the Santa Barbara Channel Ecological Preserve and Adjunct and portions of the Channel Islands National Marine Sanctuary, which are discussed separately.

b. Description of the environment: This region between the Channel Islands and the Santa Barbara and Ventura County coasts is a diverse ecological and sociological resource. A great variety of intertidal habitats dot the shoreline, while offshore many species of fish and shellfish find refuge in or migrate through the channel. Pinniped (seal and sea lion) rookeries and haul-out areas occur on the Channel Islands. A large number of marine birds use the Islands as a base for feeding in the Channel. Giant kelp grows in shallow areas.

Recreation and tourism are important economic factors in Santa Barbara County. The scenic quality of the coastline, the accessibility of rocky intertidal areas for tidepooling, and the numerous sandy bathing beaches attract many tourists. All of this contributes significantly to the local economy. Sportfishing out of Santa Barbara, Ventura, and Channel Islands Harbour contributes over $20 million to the local economy (Granville Corporation, 1981). Tours to Channel Islands National Park further increase the economic value of the channel area. Commercial fishing ventures for giant kelp, abalones, sea urchins, California spiny lobster, spot and ridgeback prawns, market squid, northern anchovy, Pacific salmon, jack mackerel, rockfishes, and California halibut, among many others, are a vital sector of the local economy. Maricultural activity, primarily, in the research and development phase now, promises future economic benefits to the area from the Santa Barbara Channel.

c. Potential impacts avoided by deferral of this subarea: Deferral of the Santa Barbara Channel subarea would reduce the risk of an oil spill and potentially adverse environmental effects on those blocks deferred.

d. Deferral recommended by: State of California, California Coastal Commission, City of Santa Barbara, Santa Barbara County, Get Oil Out, Lompoc City.

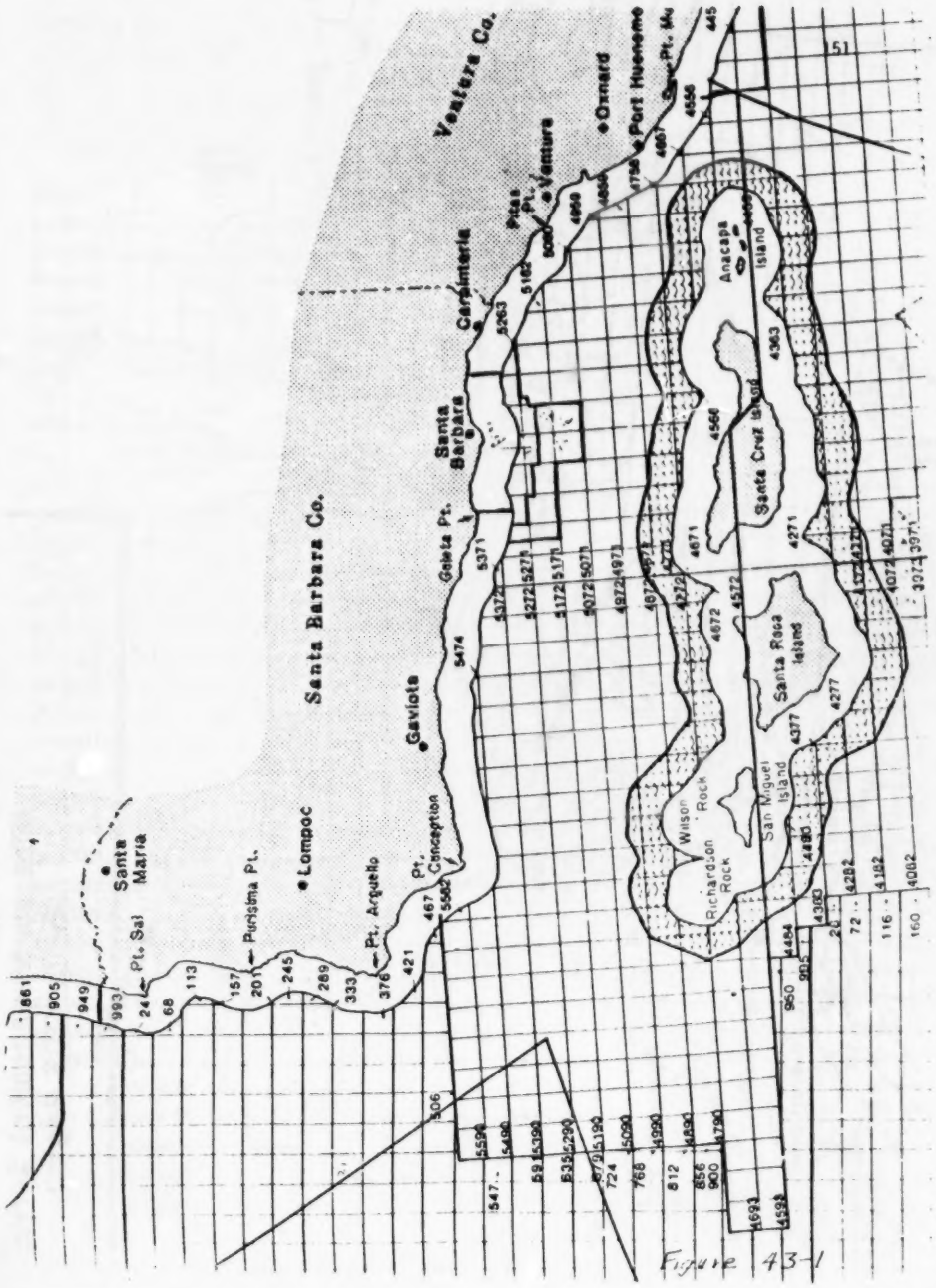


Figure 43-1

Southern California

Morro Bay Sub Area

a. Geographic description: Morro Bay is located in San Luis Obispo County. It is located approximately half way between Los Angeles and San Francisco. The Morro Bay subarea consists of a 10 mile radial zone centered on the bay. On the north it is bounded by Point Estero, on the south by Point Bachon. This subarea consists of approximately 23,000 acres. It would remove 12 whole or partial tracks from oil and gas related development (see figure 3.B-1).

b. Description of the environment: Morrow Bay is actually a lagoon rather than a true bay. Deposition of sand formed the existing sand spit which resulted in Morro Bay evolving into a lagoon. It is about 4 miles long and has a maximum width of approximately 1 3/4 miles.

Morro Bay is considered one of the largest and most significant wildlife habitats along the California coast. The salt marsh, tidal mud flats, open water, and upland vegetations provide a rich and varied habitat which supports numerous estuarine and terrestrial animals rarely exceeded in other parts of the State. At low tide, approximately 1,400 acres of tidal mud flats are exposed (NOAA, 1982). The tidal flats, salt marshes, and adjacent habitats of Morro Bay provide an extensive feeding ground for various species of shore birds and waterfowl. Seabird colonies occur on Morro Rock and the Estuarine areas behind it. Many migrant shorebirds commonly use the coastal waters (up to 100 meter depth) along the coast as well as the Bay and its estuarine areas habitats. Two endangered species receive much local attention. The peregrine falcon nests on Morro Rock. The Morro Bay kangaroo rat is indigenous to the southern end of the bay. Other species include the southern sea otter, California brown pelican, and the salt marsh harvest mouse. Morro Bay is also used for recreation, scientific research, bird watching, hunting, sportsfishing, and oyster mariculture.

c. Potential impacts avoided by deferral of this subarea: Deferral of this subarea would have the effect of assuring that no leasing; and consequently, no exploration or development activities would occur within 10 miles of Morro Bay. Negative environmental impacts associated with,oil and gas development would either not occur or would be ameliorated by both distance and time. For example, should an oil spill occur it would occur outside of this subarea which would allow for additional time for cleanup, containment, and weathering of the oil before it drifts into Morro Bay.

Water and air quality should not be directly impacted by oil and gas development. Discharges which do not enter the water or air are expected to be diluted to near ambient levels by the time they enter the subarea. The biological community will not be impacted by platform construction activities, oil spills, drilling muds., etc.

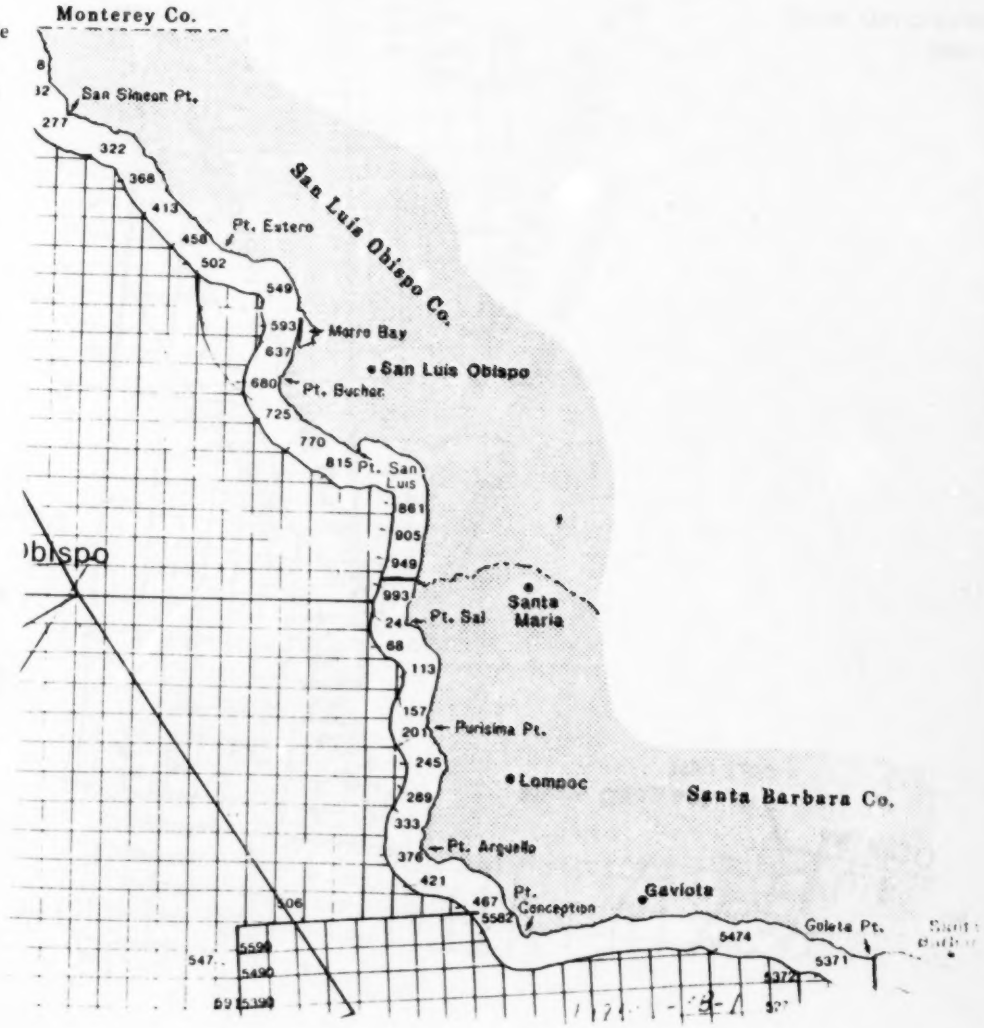
Local impacts would be reduced to the following resources: Commercial fishing, sportsfishing, recreation and tourism, visual resources, cultural resources and ports and harbors.

d. Resource potential: In terms of quantity and quality, the geotechnical data available in the proposed deletion area are sufficient to define specific traps throughout the area and structural traps have been identified throughout the mapped area.

Stratigraphic traps may be present throughout the central and southern parts of the area.

Possible exploration/discovery trends within or adjacent to the subarea include the Farallon-Pigeon Point High which extends across the northern part of the area. A poorly defined anticlinal trend extends northwestward across the northwest part of the area. The Palo-Colorado-San Gregorio Fault Zone extends across the eastern part of the area.

e. Referral recommended by: San Luis Obispo County, also see other related areas overlapping Morro Bay.



Southern California

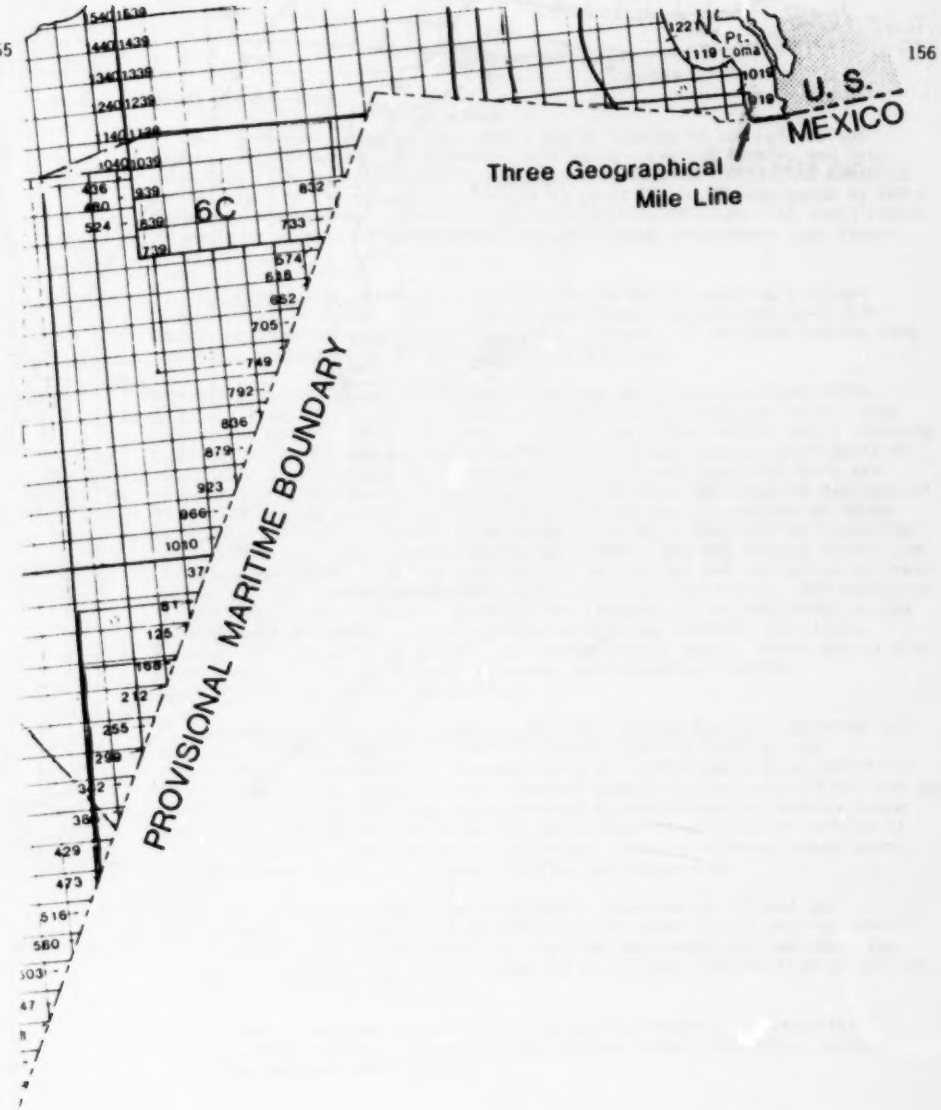
Defer the Tactical Maneuvering Area P-4 and Portion of W-21 connect-P-4 to FLETA HOT

a. Geographic description: This subarea deferral would remove approximately 28 complete and partial tracts from the proposed offering area. These tracts are located 80 to 100 miles southwest of San Diego and abutting the U.S./Mexico Maritime boundary (see Figure 13-1).

b. Description of the environment: This area is an operating area for avanced air intercept and air combat maneuvering and is used for all weather flight training, aircraft carrier and submarine operations, and other miscellaneous hazardous operations.

c. Potential impacts avoided by deferral of this subarea: Deferral of this subarea would reduce the potential impact to the military uses of the area.

d. Deferral recommended by: State of California, San Diego County.



Southern California

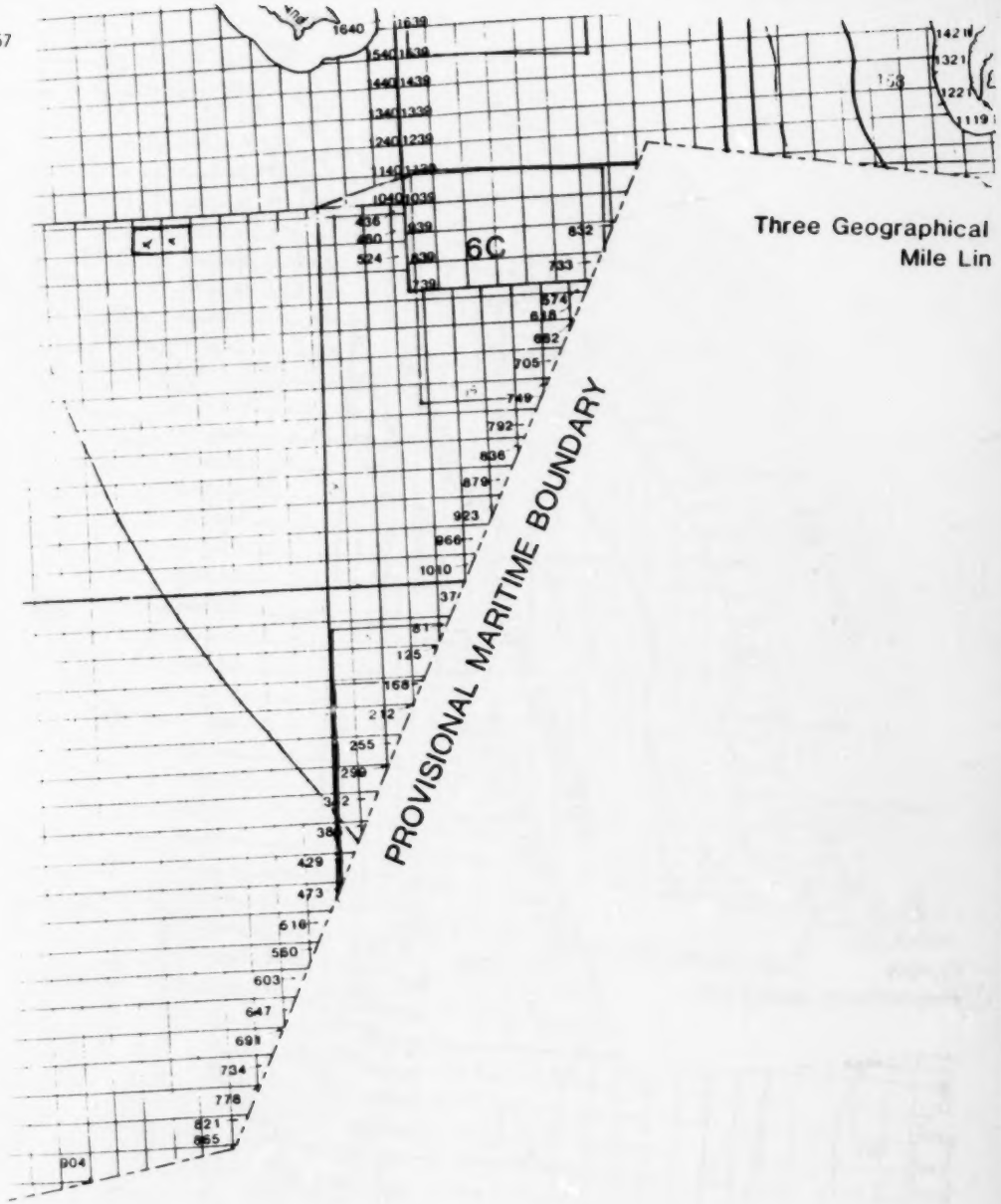
Defer the Towed Fleet Training Area HOT (FLETA HOT)

a. Geographic description: This subarea deferral would remove approximately 146 complete and partial tracts from the proposed offering area. These tracts are located 35 to 85 miles southwest of San Diego and abutting the U.S./Mexico Maritime boundary (see Figure 14-1).

b. Description of the environment: This area is an open ocean area which is heavily used for fleet training. It is an area of hazardous operations, with primarily surface and anti aircraft gunnery, and anti submarine warfare training occuring there. Due to the use of live ordinance, this area is considered hazardous for both navigation and flight.

c. Potential impacts avoided by deferral of this subarea: Deferral of this subarea would reduce the potential impact to the military uses of the area.

d. Deferral recommended by: State of California, San Diego County.



Southern California

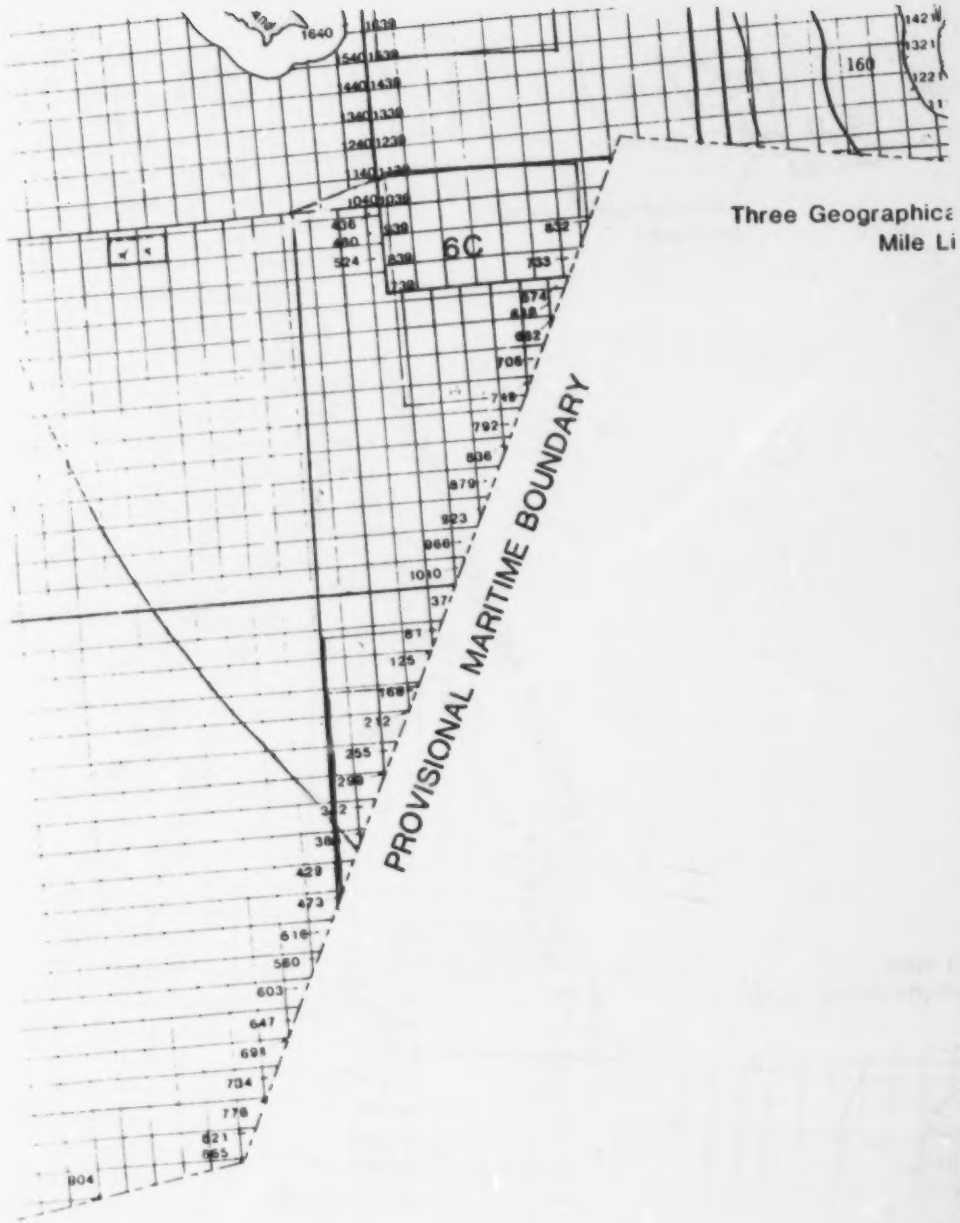
Defer the Coordinated ASW Services and Training Area 2 (CAST 2)

a. Geographic description: This subarea deferral would remove approximately 61 complete and partial tracts from the proposed offering area. These tracts are located 40 to 60 miles southwest of San Diego, are in the northern portion of FLETA HOT (subarea 14), and abutting the U.S./Mexico Maritime boundary (see Figure 15-1).

b. Description of the environment: This area is an open ocean area used for coordinated Anti Submarine Warfare Training which includes the use of torpedoes, anti submarine rockets, and other anti submarine warfare weapons. This area lies within the boundary of FLETA HOT, and such is considered a hazardous area for both navigation and flight.

c. Potential impacts avoided by deferral of this subarea: Deferral of this subarea would reduce the potential impact to the military uses of the area.

d. Deferral recommended by: State of California, San Diego County.



Southern California

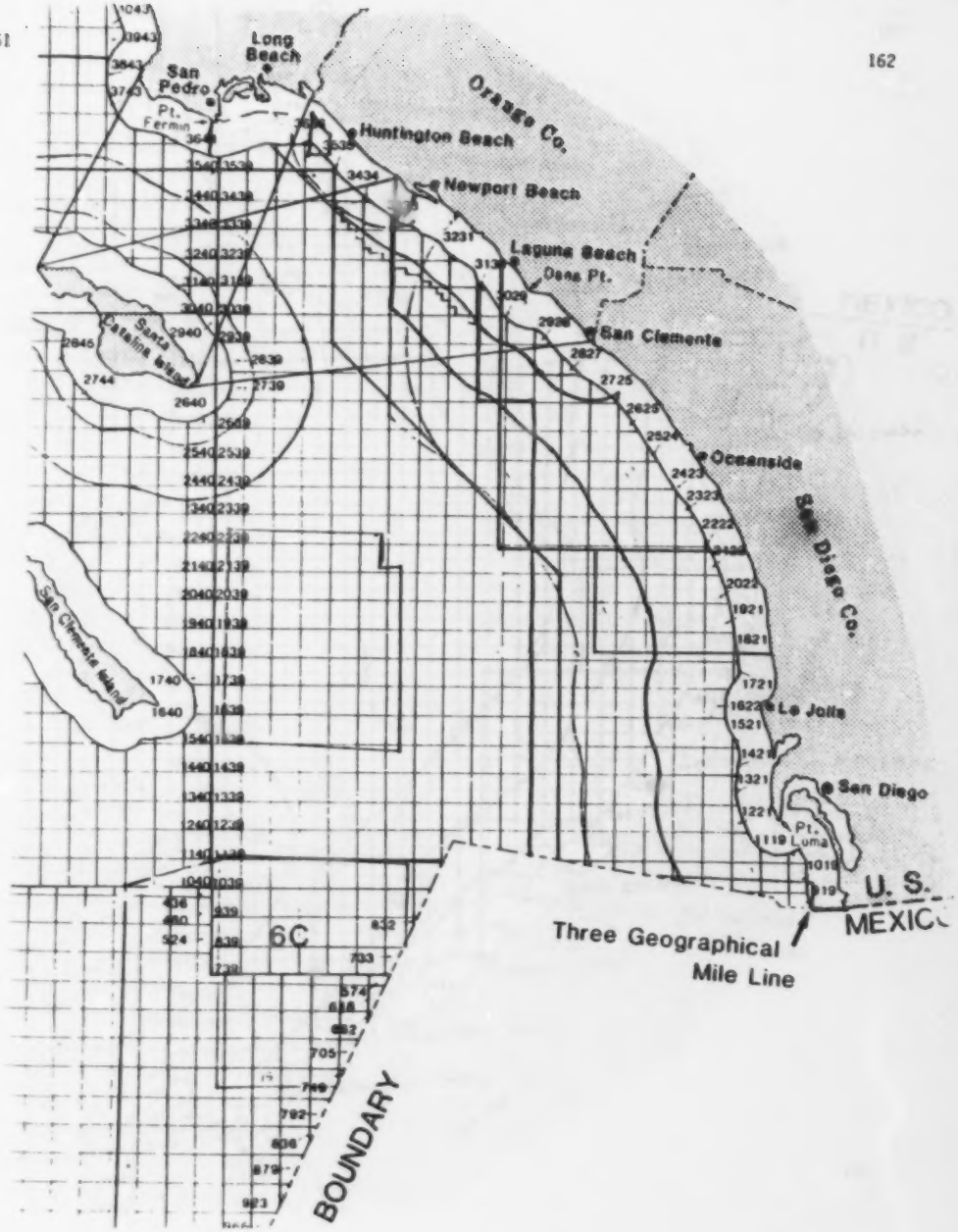
Defer the Shallow Water Coordinated Anti-Submarine Warfare Service and Training Area 1 (CAST 1)

a. Geographic description: This subarea deferral would remove approximately 62 complete and partial tracts from the proposed offering area. These tracts are located approximately 6 miles east of San Clemente Island and about 37 miles west of La Jolla (see figure 16-1).

b. Description of the environment: This is the primary open ocean area in Southern California which is used for Coordinated Anti Submarine Warfare Training, using torpedoes, anti-submarine rockets, and other anti submarine warfare.

c. Potential impacts avoided by deferral of this subarea: Deferral of this subarea would reduce the potential impact to the military uses of the area.

d. Deferral recommended by: State of California, San Diego County.



Southern California

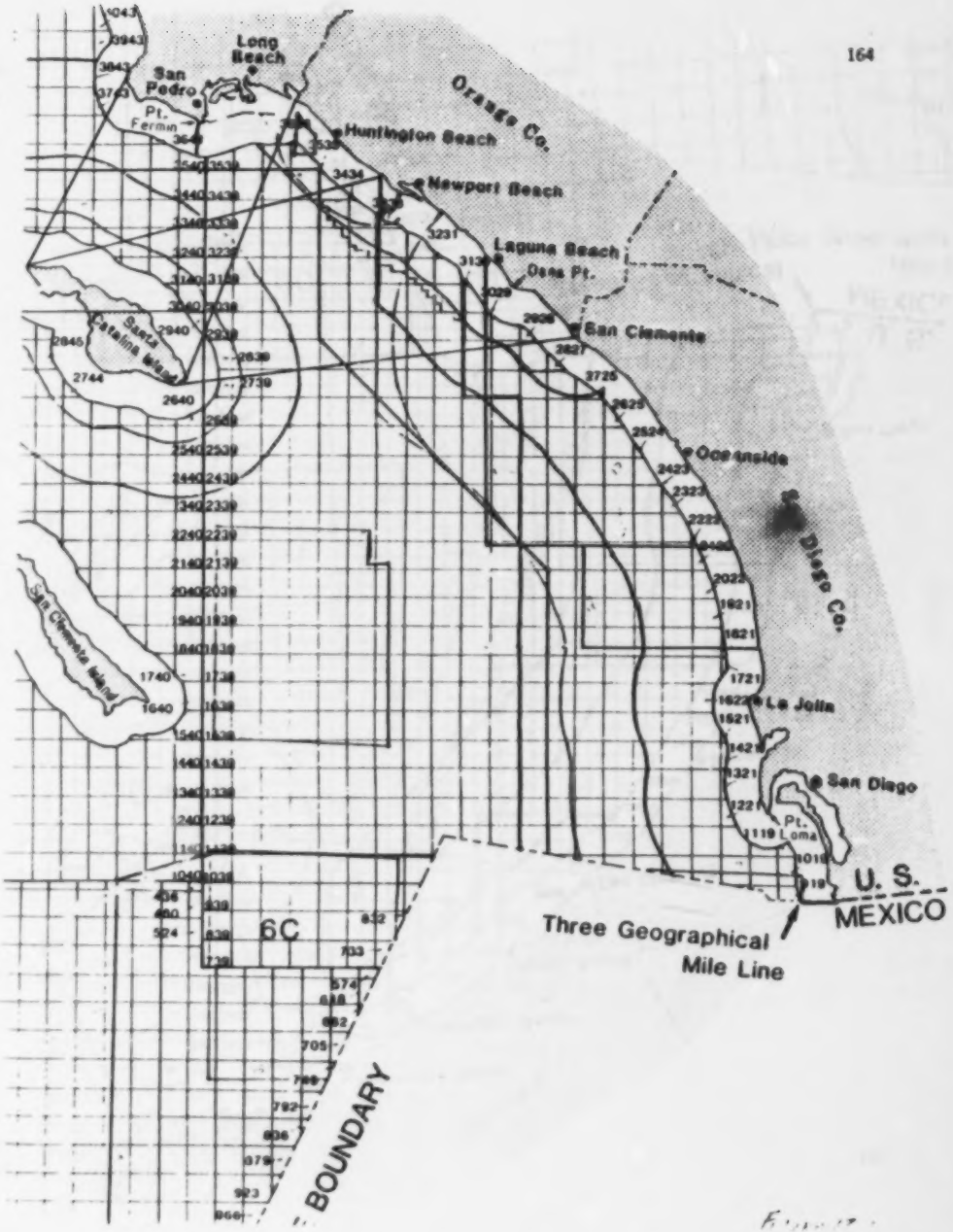
Defer the Camp Pendleton Amphibious Assault Area (CPAAA)

a. Geographic description This subarea deferral would remove approximately 43 complete and partial blocks from the proposed planning area. These tracts are located off Camp Pendleton Marine Corps Base in a triangular area bounded by a line running due south from Laguna Beach for about 30 miles due east to the coast just south of Carlsbad (see figure 17-1).

b. Description of the environment: This is an ocean area used for amphibius operations, simulated dive, glide and low level bombing, simulated rocket firing and strafing, and free ballon operations. No live ordinance is used in this area. The coastline in this area is also important for recreational resources and significant biological areas.

c. Potential impacts avoided by deferral of this subarea: Deferral of this subarea would reduce potential local impacts to military uses and other resources.

d. Deferral recommended by: State of California, San Diego County.



Southern California

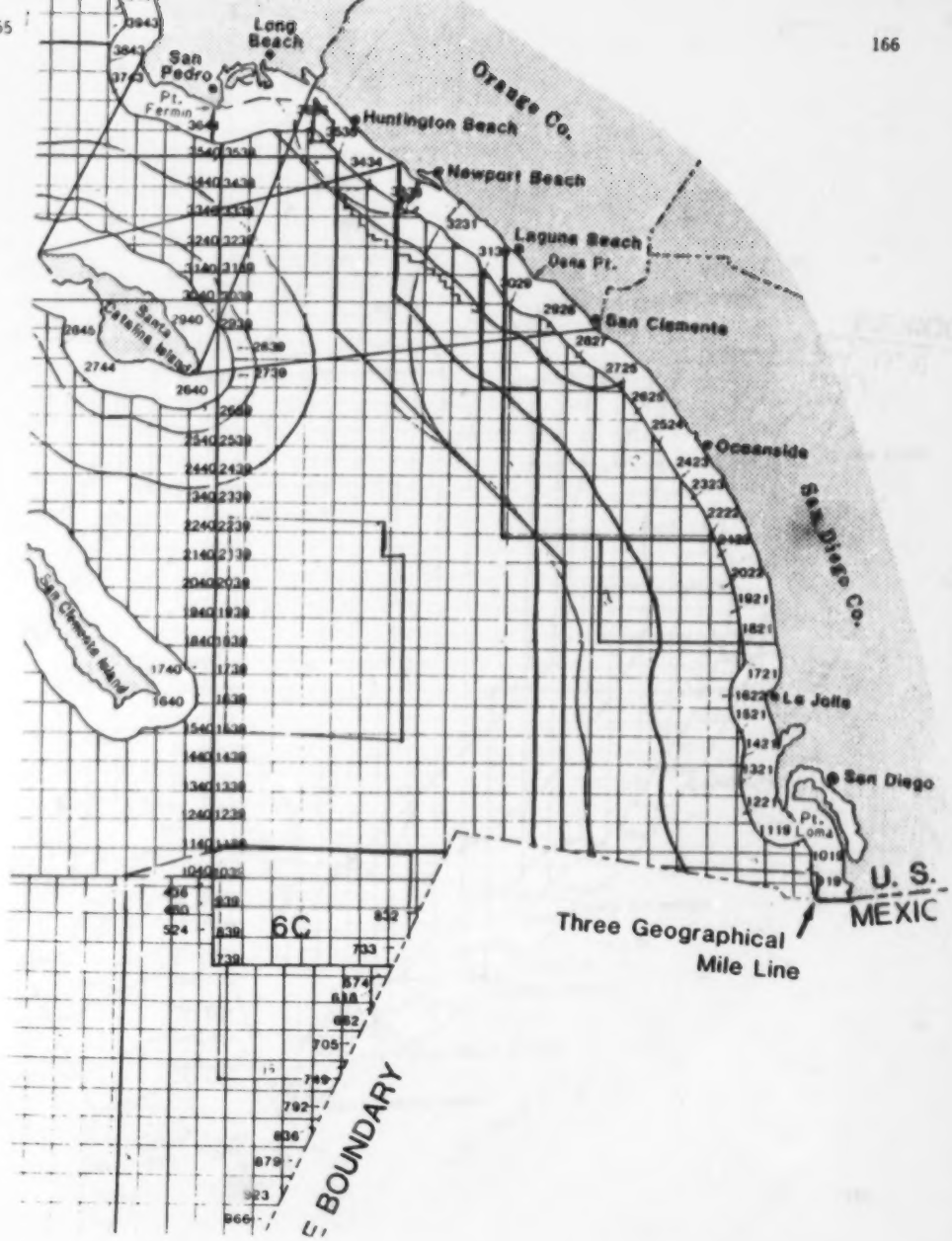
Defer the Encinitas Naval Electronics Test Area (ENETA)

a. Geographic description: This subarea deferral would remove approximately 26 complete and partial tracts from the proposed planning area. These tracts are located offshore Encinitas, immediately to the south of CPAAA and extended approximately 18 miles offshore (see figure 18-1).

b. Description of the environment: This is an ocean area used for electronic testing, including fleet training, independent steaming exercies, and torpedo firing. The coastline in this area is also important for recreational and biological resources, as described in the deferral proposed offshore San Diego county.

c. Potential impacts avoided by deferral of this subarea: Deferral of this subarea would reduce potential local impacts to military uses and other resources as described for the subarea deferral proposed offshore San Diego County.

d. Deferral recommended by: State of California, San Diego County.



Southern California

Defer the Coronado Island Submarine Training Area (CISTA)

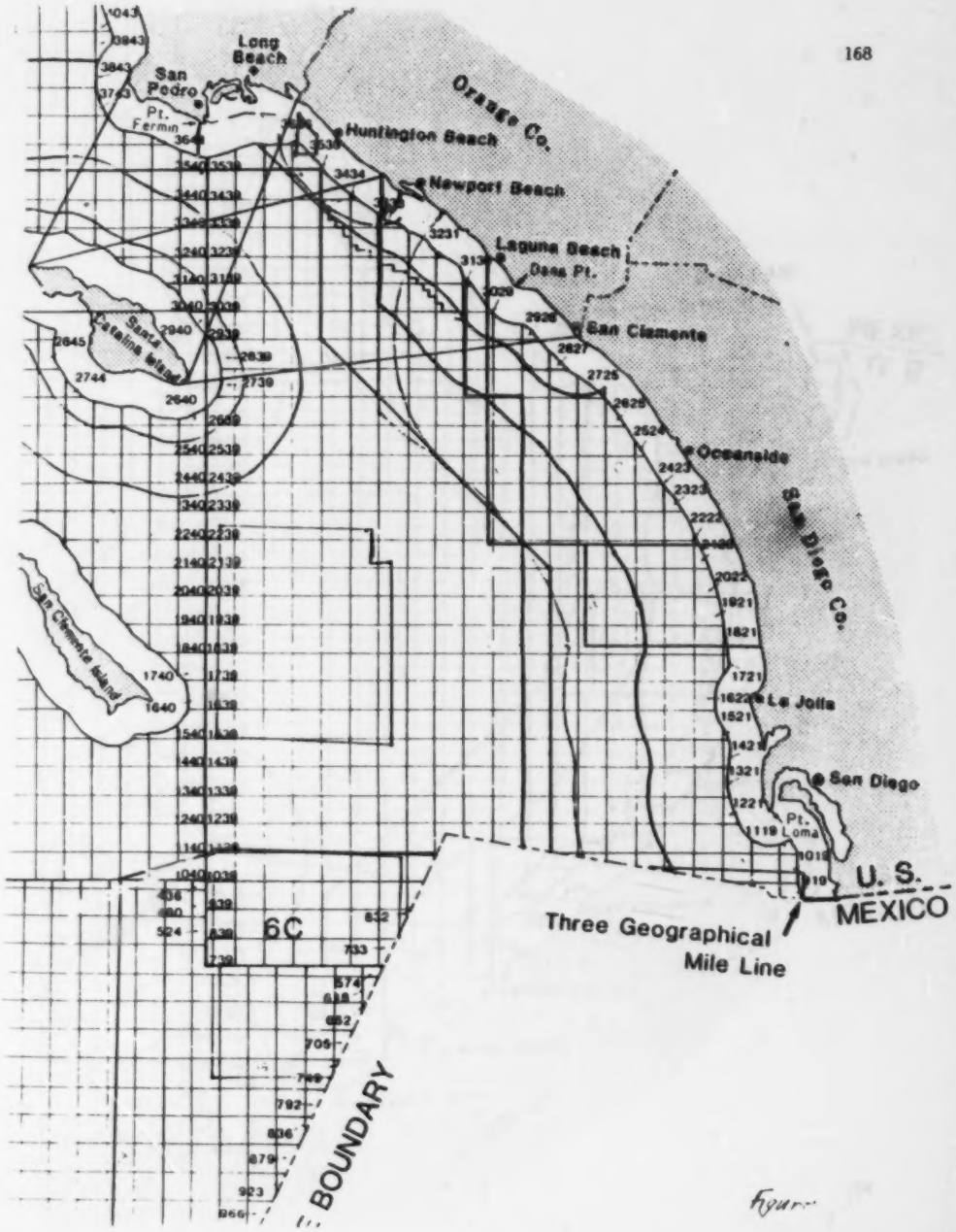
a. Geographic description: This subarea deferral would remove approximately 10 partial tracts from the proposed planning area. These tracts are situated off Imperial Beach and extend approximately 26 miles from shore adjacent to the U.S./Mexican Maritime Boundary (see figure 19-1).

b. Description of the environment: This is an ocean area used for submarine training, helicopter anti-submarine warfare training, and fleet training. Firing of ordance in this area is confined to W-291. However, CISTA should be considered as a hazardous area for navigation.

The coastline in this general area is also important for recreational and biological resources as described for in the deferral proposed offshore San Diego County.

c. Potential impacts avoided by the deletion of this subarea: Deferral of this subarea would reduce potential local impacts to military uses, and other resources as described for the subarea deferral proposed offshore San Diego County.

d. Deferral recommended by: State of California, San Diego County.



Figure

Southern California

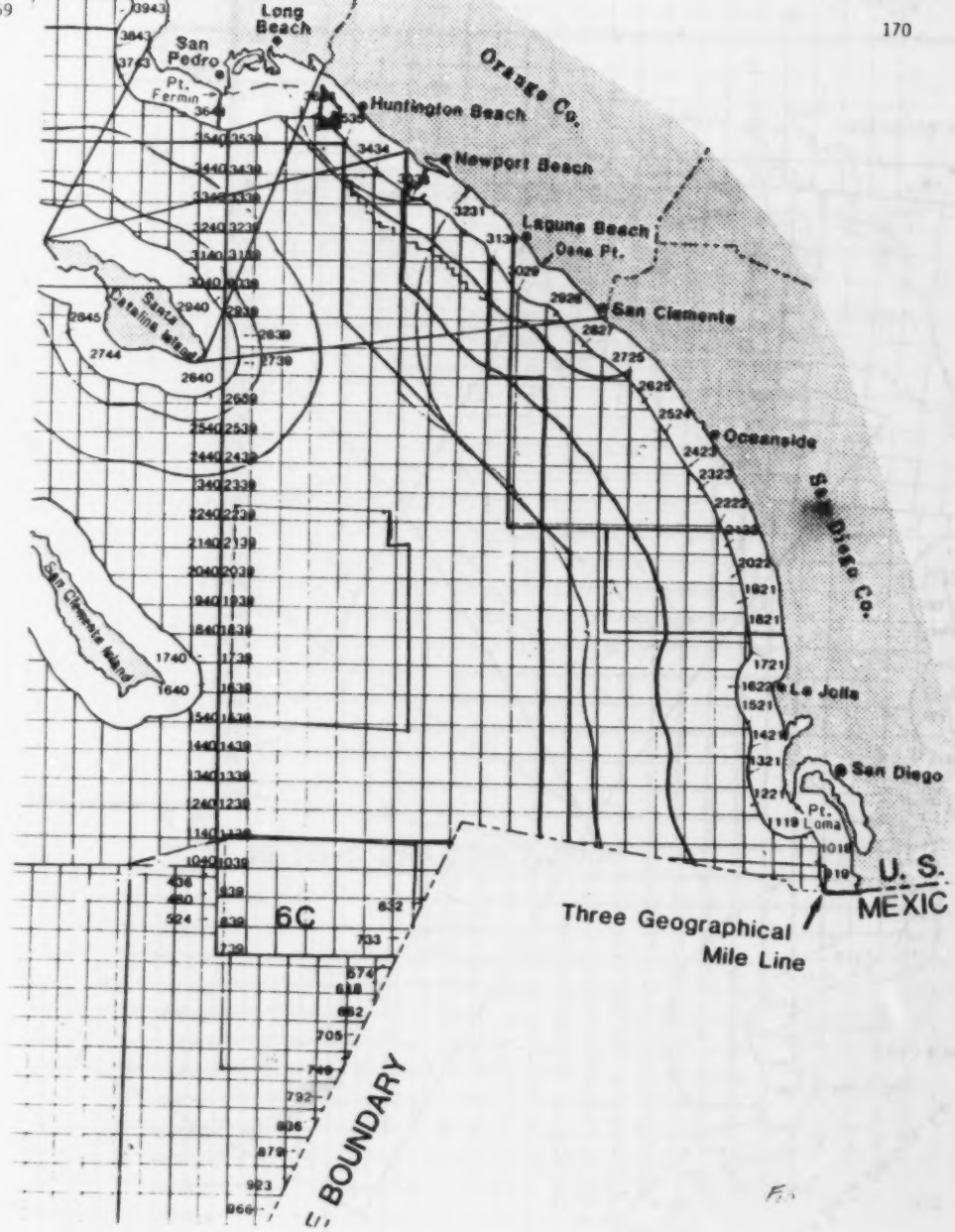
Defer the Combat Systems Evaluation Range/Shipborne Electronics System Evlauation Facility

a. Geographic description: This subarea deferral would remove two partial tracts from the proposed offering area. These tracts are situlated off Long Beach and Huntington Beach, and are adjacent to the three mile line and the vessel precautionary area (see figure 20-1).

b. Description of the environment: This area is a system evaluation range used for testing antenna radiation patterns, passive electronic counter measures, and variuus electronic systems testing and calibration. The coastline in this area is also important for recreational and biological resources as described for the Orange County subarea.

c. Potential impacts avoided by the deferral of this subarea: Deferral of this subarea would reduce potential local impacts to military uses and other resources as described for the Orange County subarea.

d. Deferral recommended by: State of California, San Diego County.



Southern California

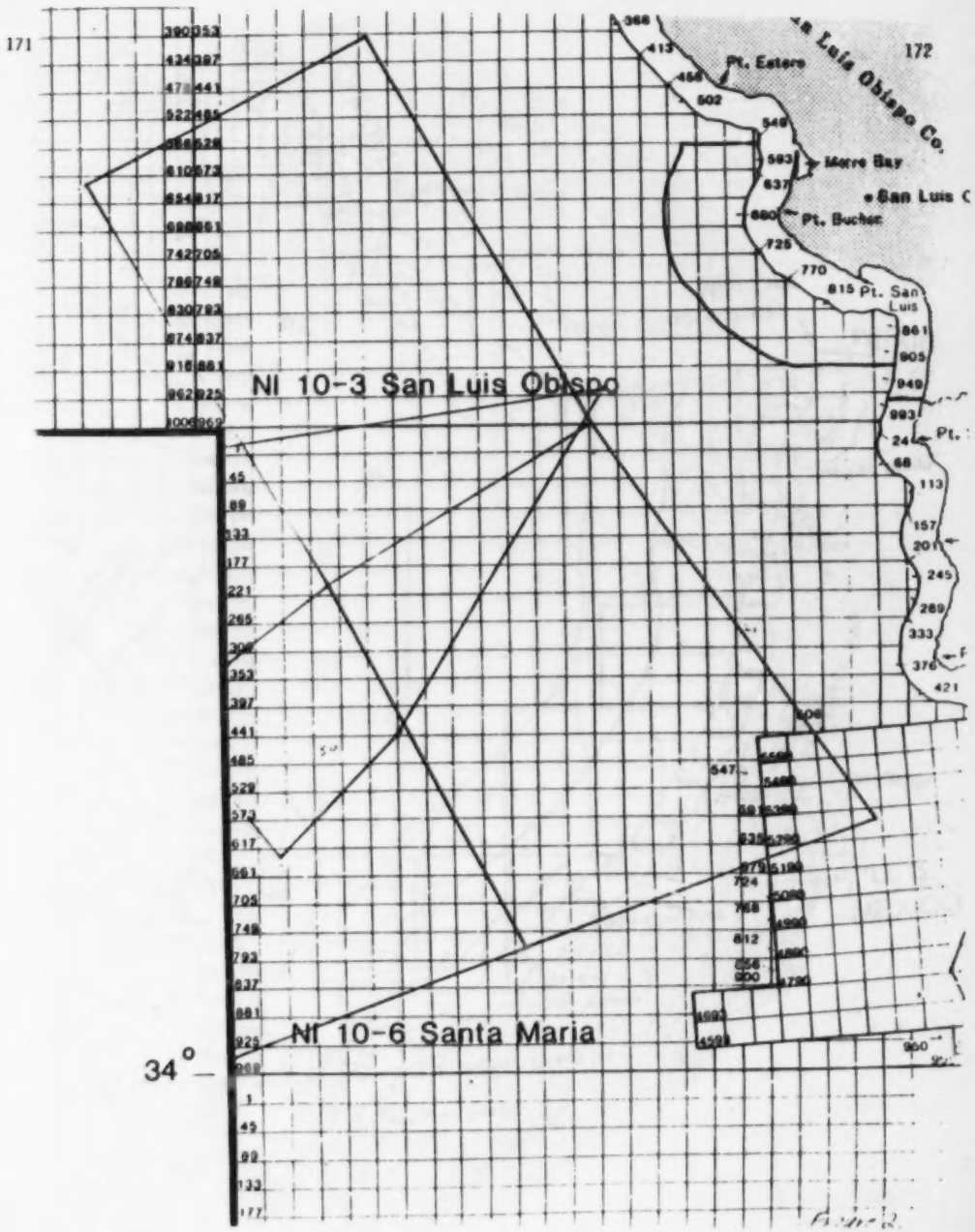
Defer Waring Area W-532 in the northern section of the Pacific Missile Test Center (PMTC)

a. Geographic description: This subarea deferral would remove approximately 522 complete and partial tracts from the proposed offering area. These tracts are located 18 to 80 miles off Point Conception and extend north to a point about 35 miles west of Morro Bay (see figure 21-1.

b. Description of the environment: This area is an open ocean area used by PMTC to test missile systems. PMTC is located at Point Mugu and conducts several hundred weapon systems lauches each year. Launch operations are within defined limits; and the surface area within these areas and the air space above must be clear throughout the launch. Due to the testing of these weapon systems, this area should be consideredhazardous for both navigation and flights.

c. Potential impacts avoided by deferral of this subarea: Deferral of this subarea would reduce the potential impact to the military uses of the area.

d. Deferral recommended by: State of California, San Diego County.



Central California

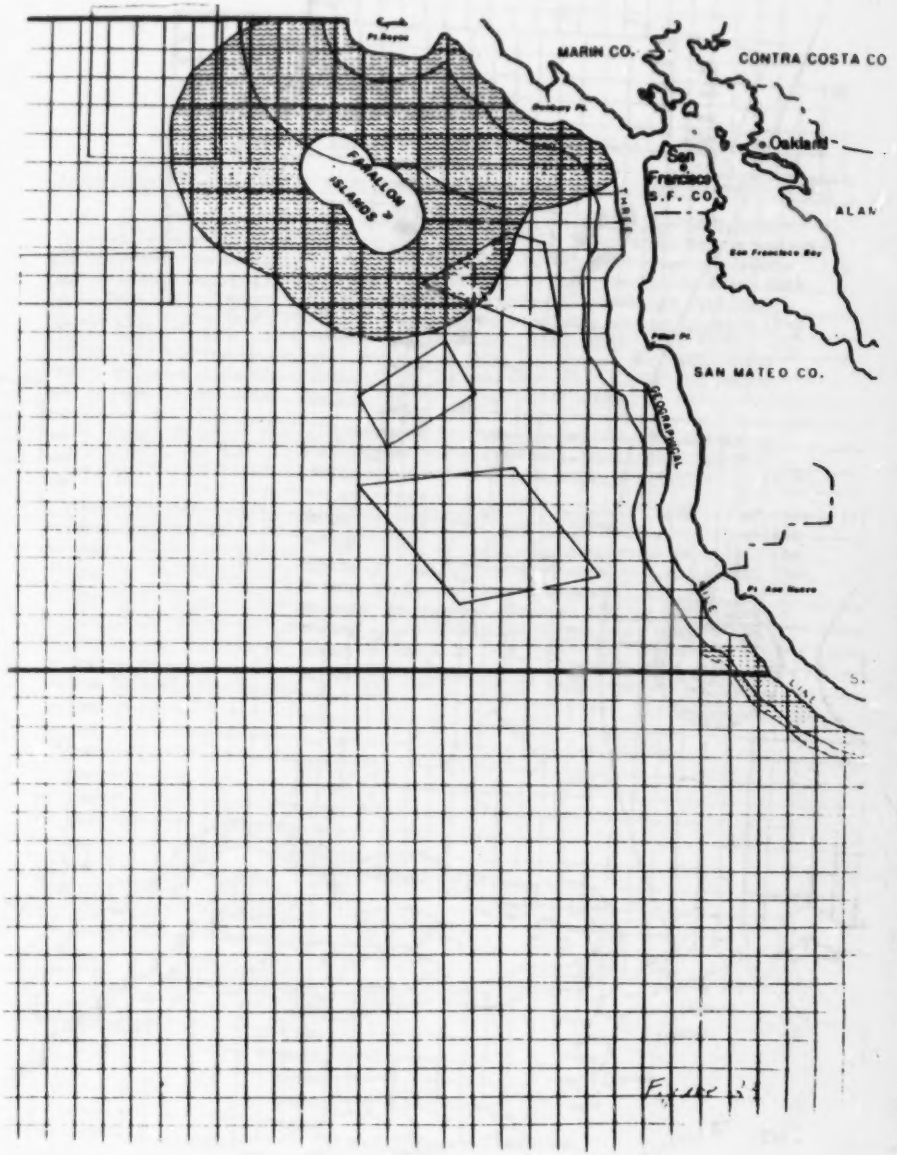
Defer the San Francisco Submarine Diving Areas Uniform 1, 2, 3, 4, and 5

a. Geographic description: This subarea deferral would remove approximately 130 complete and partial tracts from the proposed offering area. These tracts are distributed over 5 areas (Uniform 1,2,3,4 and 5 and are situated 9 miles west of Pacifica, 20 miles west southwest of Pitta Point, 20 miles west southwest of Point Reyes, 24 miles west southwest of the Farallon Islands and 18 miles west of Pescadero Point, respectively (see figure 23-1).

b. Description of the environment: These are open ocean areas used for submarine testing and training after refitting. Each area is used for different types of tests in shallow dives and deep dives. This is the only area in central California where these tests can be carried out due to the proximity to the yards and the bottom topography.

c. Potential impacts avoided by deferral of this subarea: Deferral of this subarea would reduce the potential impact to the military uses of the area.

d. Deferral recommended by: State of California, San Diego County.



Southern California

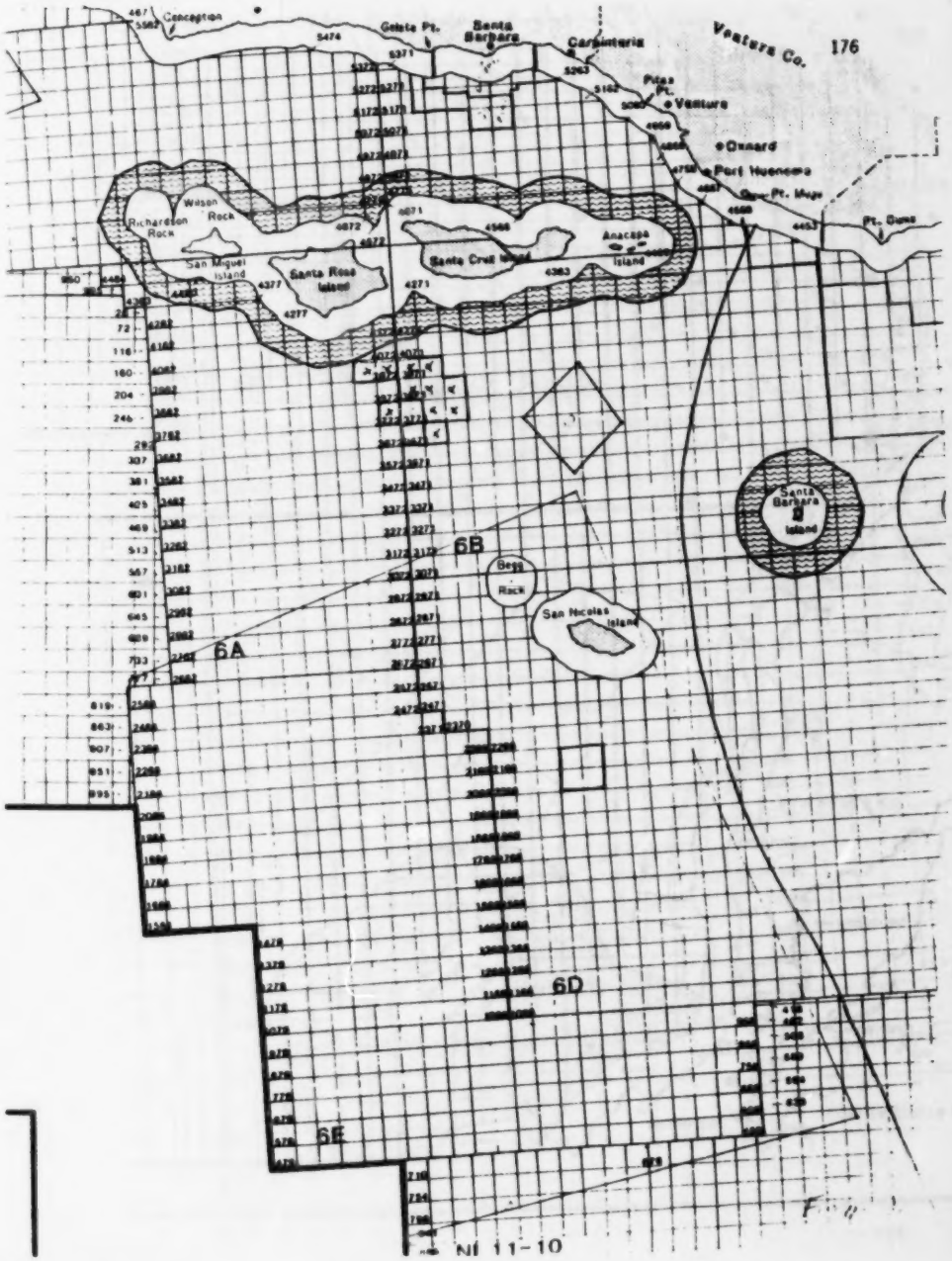
Defer Vandenberg Air Force Base Space Shuttle Impact Area

a. Geographic description: This subarea deferral would remove approximately 746 complete and partial tracts from the proposed offering area. These tracts are situated in an area 75 to 100 miles wide, approximately 100 to 200 miles south southeast from the shuttle launch facility to Vandenberg (see figure 24-1).

b. Description of the environment: This area is an open ocean area which will be used as an impact area for the solid rocket boosters which are utilized for space shuttle launching. These boosters are dropped off, and are recovered for reuse. This area is scheduled to be used for this purpose starting early 1986.

c. Potential impacts avoided by deferral of this subarea: Deferral of this subarea would reduce the potential local impact to the military uses of the area.

d. Deferral recommended by: State of California, San Diego County.



Northern, Central and Southern California

3-mile buffer zone adjacent to the California State oil and gas sanctuaries.

a. Geographic description: All blocks within a 3 mile zone adjacent to the California State oil and gas sanctuaries (see Sale 73 and 80 FEIS's). The State oil and gas sanctuaries range from the Oregon/California boundary to the Santa Maria river mouth; from Goleta Point to Carpinteria; from the Ventura-Los Angeles County border to Point Fermin and from Newport Beach to the United States-Mexico border; waters around Santa Catalina and San Clemente Islands and extending to the three mile limit of the state tide and submerged lands.

b. Description of the environment: The subarea deletion would consist of portions of the zone defined by Section 8(g) of the Outer Continental Shelf Lands Act, as amended. Some of the major areas which this zone would be adjacent to are: Pt. Reyes Wilderness Area; Pt. Ano Nuevo; Big Sur Coastline; Monterey Bay; Sea Otter Range; Morro Bay; Santa Monica Bay; Orange and San Diego county coastlines and off Santa Catalina and San Clemente Islands. Physical, biological and socioeconomic resources located within these areas are described in detail within the specific subarea deferrals.

c. Potential impacts avoided by deferral of this subarea: Deferral of this subarea would eliminate potential 8(g) tracts of the State oil and gas sanctuaries. This would eliminate any potential revenue to the State of California from the leasing and development of these tracts.

The deferral of these tracts would also create a 3-mile buffer zone which would provide additional time for the weathering, diversion and cleanup of an exploration or development related oil spill. In the event an oil spill should occur, the areas and associated resources along the California coast would be provided protection.

The deferral of the area would reduce localized water quality and visual impacts associated with the elimination of any placement of platforms within the subarea.

d. Deferral recommended by: California Assembly.

Northern, Central, and Southern California

Areas within 6 miles of 22 significant marine mammal and seabird resource areas.

a. Geographic description: The California Coastal Commission recommended that no leasing occur in the following areas: Point Arena Basin tracts within six miles of the Mendocino coast from Elk Creek to Ten Mile river and within six miles of the coast from Point Arena to Gerstle Cove, including Arena Rock, Seal Haul Rock, Saunder's Reef, Sea Lion Rocks, Haven's Neck and Fish Rocks; Bodega Basin tracts within the proposed marine sanctuary boundary; Santa Cruz Basin tracts within six miles of San Pedro Rock, Three Rocks, Eel Rocks, Seal Rocks, and the coast extending south from Point Ano Nuevo; and Santa Maria Basin tracts within six miles of Point Buchon, Morro Rock, Lion and Pecho Rocks, the Nipomo Dunes, and the California sea otter range.

b. Description of the environment: This subarea contains the entire sea otter range, Ano Nuevo and many other rocks and reefs important to several other species of seabird and marine mammals. These areas are also very scenic.

c. Potential impacts avoided by deletion of this subarea: Deferral of this subarea would prevent oil and gas development activities from occuring within 6 miles of the above areas. If an OCS related spill does occur it will occur at least 6 miles offshore of these areas. This will allow for additional time for weathering, dispersion, diversion, and cleanup of an OCS oil spill. All other impacts associated with OCS development, such as air and water quality degredation, noise pollution and visual disturbance from platforms, crew boats and helicopters will be eliminated in this 6-mile buffer area.

d. Deferral recommended by: California Coastal Commision.

Southern, Central, Northern California

No leasing North of the Santa Maria River Mouth

a. Geographic description: The subarea deferral would remove those blocks which range from the Santa Maria River mouth (Row N808, UTM grid system) to the California-Oregon Boundary.

b. Description of the environment: Located within the subarea deletion are the following areas: Eel River, Pt. Arena, Bodega, and Santa Cruz Basins; Cape Mendocino, Mendocino coastline; San Francisco Bay; Pt. Reyes Wilderness Area; Pt Reyes-Farallon Island Marine Sanctuary; Pt. Ano Nuevo; Big Sur Coastline; Morro Bay and Sea Otter range (see specific subarea deletions for a discussion on the physical, biological, and socioeconomic environment associated with these areas).

c. Potential impacts avoided by deferral of this subarea: With the deferral of this subarea potential impacts to the physical, biological, and socioeconomic environment from oil and gas development (oil spills, platform construction and placement, exploration/development/production activities, etc.) within the subarea would be eliminated on those blocks deferred.

d. Deferral recommended by: California Coastal Commission, City of Morro Bay, City of Pismo Beach.

Northern and Central California

Areas off the Northern and Central California Coastline including areas offshore the rural scenic and undeveloped coastal areas of Mendocino, Sonoma, Marin, San Mateo, and Santa Cruz counties (CCC staff report)

a. Geographic description: The northern and central California coastline subarea deletion would range from the Oregon-California boarder to San Luis Obispo/Monterey county line.

b. Descritpion of the environment: Some of the major areas within the subarea are: Mendocino coastline; Pt. Reyes Wilderness Area; Pt. Reyes/Farallon Island Marine Sanctuary; San Francisco Bay area; Monterey Bay; Northern portion of the Sea Otter range and the Big Sur coastline. These areas and associated resources are discussed in the specific subarea deletions.

c. Potential impacts avoided by deletion of this subarea: Deletion of the areas off the northern and central California coastline would eliminate any impacts associated with oil and gas exploration and development to any of the resources within the area (see discussions for specific basin subarea deletions).

d. Deferral recommended by: California Coastal Commission.

Northern and Central California

No leasing North of Morro Bay

a. Geographic description: The subarea deferral would defer those blocks which range from Row N816, UTM system (Morro Bay Area) to the California-Oregon boundary.

b. Description of the environment: Located within the subarea deferral are the following areas: Eel River, Pt. Arena, Bodega, and Santa Cruz Basins; Cape Mendocino, Mendocino coastline; San Francisco Bay; Pt. Reyes Wilderness Area; Pt. Reyes-Farallon Island Marine Sanctuary; Pt. Ano Nuevo; Big Sur coastline; and the northern portion Sea Otter range (see specific subarea deferrals for a discussion on the physical, biological and socioeconomic environment associated with these areas).

c. Potential impacts avoided by deferral of this subarea: With the deferral of this subarea potential impacts to the physical, biological, and socioeconomic environment from oil and gas exploration/development/production activities, etc.) within the subarea would be eliminated on those blocks deferred (see the specific subarea deferrals for detailed discussions).

d. Resource potentials: See specific subarea deferrals for detailed discussions.

e. Deferral recommended by: See specific subarea deferrals for detailed discussions.

Southern and Central California

Sea Otter Range

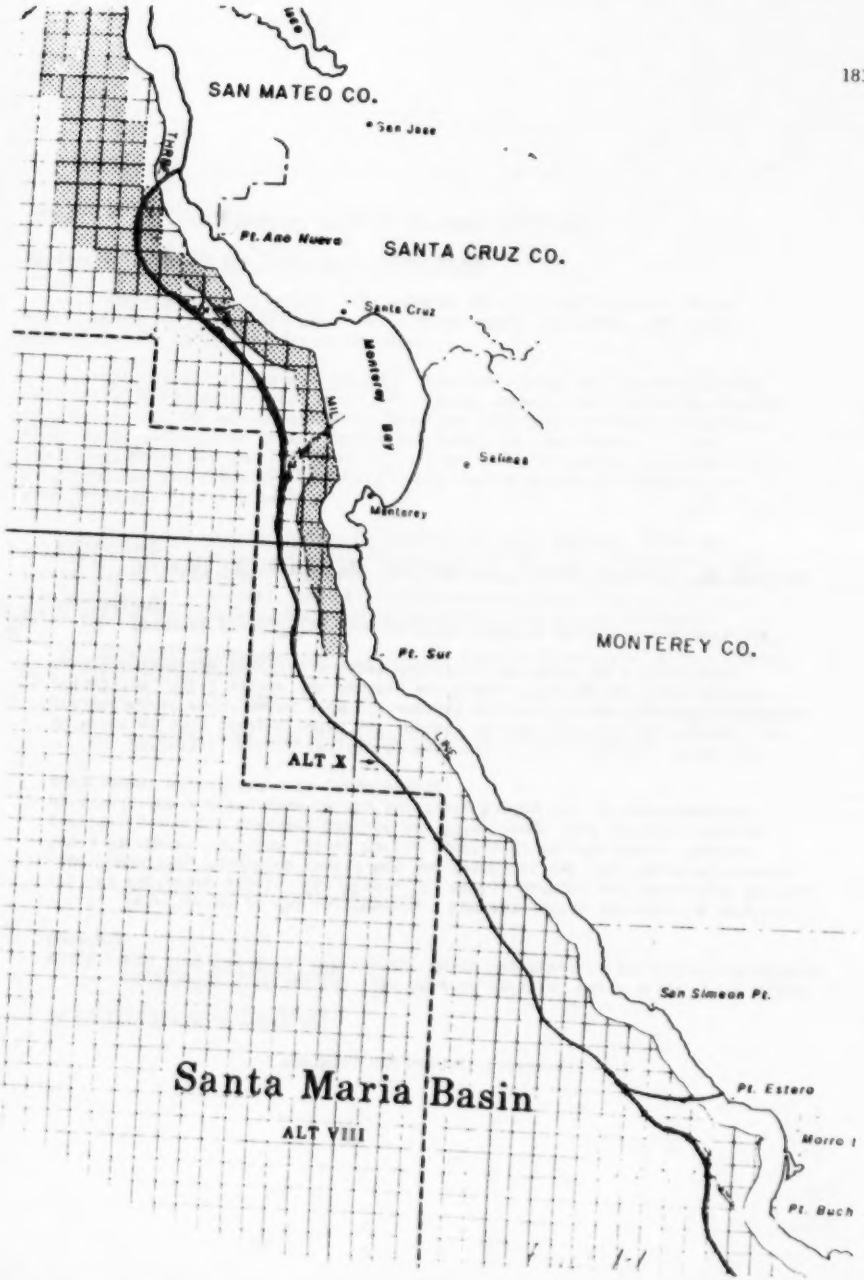
a. Geographic descriptions: The sea otter subarea is a 10 mile buffer area from northern Barbara County north to southern San Mateo County (see figure 1-1).

b. Description of the environment: This subarea includes the entire California sea otter population and range which extends from the Santa Maria River north to Ano Nuevo. The Big Sur section of the California coastline, Monterey Bay and peninsula and Ano Nuevo State Reserve are also included in this subarea (see Ano Nuevo subarea for complete description). In addition to about 1500 sea otter, thousands of seabirds, including the brown pelican, and gray whales use this section of the coast seasonally. The Elkhorn Slough which empties into Monterey Bay is an important habitat for many species of plants and animals including the endangered California clapper rail. Over one million visitors a year (Sale 53 FEIS) visit parts of this subarea, attracted to the many scenic areas and cultural attractions such as Cypress Point, Pebble Beach, the Monterey aquarium and Hearst's Castle.

c. Potential impacts avoided by deferral of this subarea: The deferral of this subarea would eliminate oil and gas exploration, development, and production activities from occurring in the Federal OCS area from 3 to 7 miles off the California coastline from near the Santa Maria River mouth north to near Point Ano Nuevo. The subsequent potential impacts from elimination of these hypothetical activities would also be eliminated on the blocks deferred. Impacts such as reduction in air and water quality resulting from normal OCS exploration, oil spills and the associated impacts on the biological and cultural environments; and impacts on the social and biological environments from normal OCS exploration, development and production activities such as disturbance from crew boats, demand from berthing areas and onshore facilities would be reduced in the deferral area. However, this deferral would not affect the possible impacts from potential oil development in State waters, Federal development seaward of the buffer, or existing non-OCS tankering and shipping activities occurring within this proposed buffer area.

The deferral of this subarea could provide additional protection by providing a greater buffer area (assuming no oil development occurs within the States 3 mile coastal area) between OCS Federal platforms and their potential oil spills from a number of environmental and cultural resources. A buffer area could allow more time for additional weathering of oil and for dispersion, diversion and/or cleanup of oil from oil spills occurring seaward of the buffer boundary.

d. Deferral recommended by: State of California, California Department of Justice, Greenpeace, League of Women Voters of San Luis Obispo, Lompoc City.



Southern and Central California

20-mile buffer around Morro Bay, 12 mile buffer from the sea otter range

a. Geographic description: This subarea is located in the same area as the sea otter subarea but extends 2 miles further out to sea and 2 miles further at the north and south end of the range. This subarea also adds an additional 10 mile buffer area seaward of Morro bay.

b. Description of the environment: (see sea otter subarea for description).

c. Potential impacts avoided by deferral of this subarea: In addition to the impacts avoided or reduced in the sea otter subarea deferral, this subarea would increase the buffer area by 2 miles from near the Santa Maria river north to Ano Nuevo and by 10 additional miles in a 20-mile arc from the entrance to Morro Bay.

d. Resource potential: In terms of quantity and quality, the geotechnical data available in the proposed deletion area are sufficient to define specific traps throughout the entire area and structural traps have been identified throughout the mapped areas.

Stratigraphic traps may be present throughout the area.

Possible exploration/discovery trends within or adjacent to the subarea include the Hosgri-Sur-Nacimieto-Palo Colorado-San Gregorio Fault Zones which extend northwest-southeast throughout the area.

e. Deferral recommended by: State of California, California Department of Justice, Greenpeace, League of Women Voters of San Luis Obispo. Lompoc City.

Washington - Oregon Planning Area

Defer the area of visual impact off the Washington and Oregon coast

a. Geographic description: This subarea deferral would remove from the planning area all partial and whole blocks within 6 miles of the Washington and Oregon coastline.

b. Description of the environment: The Washington and Oregon coastline plays a significant role in local and regional economies through tourism and recreational use.

Tourism occurs along the entire Oregon coast due to the accessability afforded by U.S. 101. Along the Washington coast, tourism is more sparse due to the lack of access to the coast north of Taholah except for a 15-mile stretch of U.S. 101 north of Queets, and access at Quillaytte and Neah Bay.

Recreational use consists mainly of camping with numerous camp sites along the coast, and sportfishng, with major salmon charter fleets out of the Washington Ports.

Significant biological areas, wetlands, estuaries, and rocky intertidal areas exist along the coast, which could suffer significant impacts should an oil spill occur and contact the coast.

c. Potential impacts avoided by deferral of this subarea: Deferral of this subarea would reduce the potential local impact to visual resources as no platform could be situated in the deferred area. This, in turn, would reduce the potential impact to tourism and recreational use.

Deferral of this subarea would provide protection for a significant number of resources in and off Washington and Oregon by precluding the possibility of an oil spill originating in the subarea and by reducing potential impacts to coastal resources by allowing additional time for weathering, diversion, and cleanup of an oil spill should one occur in areas further offshore.

Sepcific resources provided protection would be: 1) tourism and recreation resources including visual resources; 2) estuaries and wetlands; 3) biologicall significant areas; 4) rocky intertidal areas; 5) endangered and threatened species; and 6) subsistence gathering areas.

d. Oil and gas resources potential: In terms of quantity and quality, the geotechnical data available in the proposed deferral area are sufficient to define sedimentary section over the entire area.

Stratigraphic traps may be present along the flanks of the five sedimentary basins identified off the Washington-Oregon Coast that extend into the area.

Geotechnical data available is not sufficeint to define possible exploration trends.

e. Deferral recommended by: State of Oregon, City of Cannon Beach, Greenpeace, Oregon Natural Resources Council, Pacific Fisheries Enhancement Corporation.

Washington/Oregon Planning Area

Stonewall, Perpetua, and Heceta Banks (Oregon)

a. Geographic description: The deferral of these banks off of the coast of central Oregon would remove 36 whole or partial blocks from the planning area (see figure POCS 17-1). The northernmost (Stonewall) bank is delimited by the 70 m depth contour, the central (Perpetua) by the 90 m contour, and the southernmost (Heceta) by the 100 m contour.

b. Description of the environment: These banks are major commercial trawl fishing grounds, providing a large portion of the catches landed at Newport, Winchester Bay, and Coos Bay. Flatfish (flounders and sole), rockfish, lingcod, and sablefish are important catch constituents. In addition, petrale and dover sole spawn in these waters.

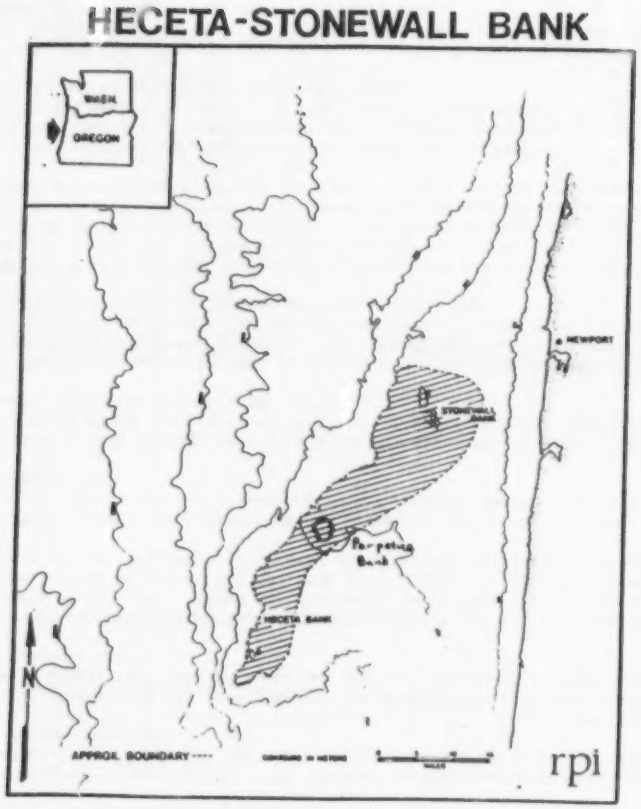
c. Potential impacts avoided by deferral of this subarea: Conflicts with commercial fishing by seismic exploration, exploratory drilling and hydrocarbon production and transportation would not occur in the deferral area. The principal impacts avoided would be gear interference from towed seismic arrays, anchor patterns, platform structural elements, pipeline laying, and increased vessel traffic. Direct damage to rockfish populations and supporting food webs (which would reduce commercial catches) from oil spills originating in the deferred areas would also be avoided. Accidents in adjacent areas could still result in negative impacts to these areas. The economy of coastal Oregon is heavily dependent on three industries; timber, fishing, and tourism. Deferral of these banks would help protect part of the tourism (recreation) industry by reducing adverse visual impacts.

d. Oil and gas resource potential: In terms of quantity and quality, the geotechnical data available in the proposed deletion area are sufficient to define sedimentary sections over the entire area of the banks.

Stratigraphic traps may be present on the flanks of the structural high underlying Stonewall Banks but there is not sufficient data to define where such traps may exist on Heceta or Perpetua Banks.

Geotechnical data available is not sufficient to define possible exploration trends.

c. Deferral recommended by: State of Oregon.



LOCATION MAP

St. George Basin Planning Area

Subarea Name:

Unimak Pass

Deferral Recommended By:

State of Alaska, Greenpeace, National Audubon Society

Geographic Description:

This option would defer the offering of 520 whole or partial blocks (2,804,924 acres) from the area available for leasing. The deferral area consists of all unleased blocks within 50 miles of Unimak Pass.

Sales (and dates held) for which the Subarea was Studied and Disposition in Each Sale:

There has been one Federal offshore lease sale in the St. George Basin. St. George Basin Sale 70 was conducted on April 12, 1983, and offered 479 tracts (2,688,787 acres) for bids. A total of 150 bids were received on 97 tracts. One high bid was rejected. Total high bids for the 96 tracts accepted (consisting of 540,917 acres) amounted to $426,458,830. Three blocks within this proposed deferral were leased. While Sale 89 has been placed on hold, decisions on the proposed notice indicated about one-half of the subarea was deferred from the sale proposal.

Oil and Gas Resource Potential:

Seismic data coverage in the Unimak Pass deferral area ranges form a detailed grid in the area north of 55° N latitude to a regional grid for areas further south. In the Unimak Pass area the Tertiary sequence reaches a total thickness of more than 20,000 feet beneath the Bering Canyon and more than 10,000 feet in Amak Basin, but thins considerable as it laps onto the flank of the northwest-trending Aleutian ridge. Potential traps underlying the shelf include anticlines, fault traps, stratigraphic onlap of Tertiary sediment onto basement highs, and sub-unconformity truncations within the basement complex. Potential traps beneath the Bering Canyon include stratigraphic pinchout of turbidite sands, rare fault-bounded traps and possible low-relief diapirs. The overall resource potential of the deferral area is moderate relative to the overall North Aleutian and St. George planning area.

Description of the Environment:

Groundfish: Pollock, halibut, and other groundfish (including eggs and larvae) spawn in the area. The eggs-larvae of one or more species may be in the upper water layers for much of the year. Adults and the demersal eggs/larvae of other groundfish species (yellow fin sole, Greenland turbot, Pacific cod) occupy water levels near the bottom.

Herring, Capelin, Smelt, and Sand Lance: These pelagic forage fishes are food for salmon, other finfishes, and the marine mammals and birds of the eastern Bering Sea. In the St. George Basin Planning Area, herring are regaining commercial importance after several decades without a fishery. Herring annually migrate inshore for spawning in the spring and to offshore overwintering waters in the fall. Both immatures and adults probably occur in coastal waters from late spring through early fall. Spawning areas approximate to the proposed Unimak Pass deferral area have not been identified; however, Japanese data indicate that migration occurs through the deferral area during spring, and there apparently is an offshore movement in the fall.

Salmonids: All American species of Pacific salmon transit waters of the proposed Unimak Pass deferral--as adults returning to Alaska streams to spawn, and as immatures enroute to the North Pacific Ocean to rear. These migrations are seasonal, annually ranging from early May through the end of September or perhaps later. As analyzed for the proposal, these migrations might be temporarily blocked or diverted by contact with oiled waters, with possible mortality and sublethal effects. The salmon food supply also might be reduced. Immature and adult salmon tend to migrate in schools that are relatively close to the surface; thus, the fish could be subject to contact by oil spills. Salmon also frequently orient their migration routes toward coastlines and off headlands.

Shellfish and Mollusks: Red and blue king crab, tanner crab, hair crab, pandalid shrimp, and several clam species are the principal shellfish and mollusks in the deferral area. Under this proposed deferral, a 50-mile offshore buffer zone from land also has been established. Portions of the deferral area are major spawning habitat for the red king crab, C. opilio tanner crab, and other shellfish and mollusks.

Marine and Coastal Birds: High bird densities occur in Unimak Pass. In particular, shearwaters forage here in summer and large numbers move between the North Pacific Ocean and the Bering Sea. Flocks of over 1 million individuals have been observed in the pass in July and August, and movements in excess of 25,000 birds/hour for extended periods have been recorded in April and May. Other species are especially abundant in migration. For example, in late March, April, and May, murres move through the pass typically at about 500 birds/hour with as many as 12,000/hour recorded. Mean density of all species in Unimak Pass in summer, including fulmars, storm petrels, gulls, and murres and other alcids, is 224 birds/km^2, or about 720,000 birds at any given moment.

Marine Mammals: Northern fur seal, harbor seal, Steller sea lion and sea otter migrate through and/or spend foraging time in this deferral area.

Endangered Cetaceans: A majority of the gray whale population (13,000-15,000) passes through Unimak Pass during spring and fall migrations each year. Gray whales may be in Unimak Pass from late March through June and from May and late November to early December. Bowhead and right whales visit the St. George Basin very infrequently (bowheads in late winter to early spring and right whales in summer). There have not been any sightings of either species in the area proposed for deferral around Unimak Pass.

Sei and blue whales are generally present during the summer months although not with any regularity, since their preferred summer feeding habitats are south of the St. George Basin. Fin whales are more frequently observed in this area than either the blue or sei whales, especially during the summer. A small local population of humpback whales may summer in the waters around Unalaska Island, a portion of which would be included in this deferral. Sperm whales prefer deeper, oceanic waters, and generally would spend only a minimal amount of time in the deferral area while migrating to and from summer feeding areas.

Commercial Fishing:

The Unimak Pass deferral would defer leasing in a number of blocks in which there is a significant amount of fishing for C. bairdi tanner crab; up to 15 percent of all C. bairdi taken in the St. George Basin since 1977-1978 have come from the deferral area.

Subsistence:

This is not an important item in the Unimak Pass area.

Potential Effects Avoided by Deferral of this Subarea:

Groundfish: Deferral of blocks within 50 miles of Unimak Pass slightly reduces the probability of oil spill contacts to any of the groundfish resources within the deferral area. Groundfish resources outside this area would be affected to the same degree as including the area for leasing.

Herring, Capelin, Smelt, and Sand Lance: The deferral of blocks within a 50-mile radius of Unimak Pass affords no incremental decrease in risk from oil spills to these species. Other factors (drilling discharges, pipeline construction, and geophysical surveys) would contribute the same level of effects as making the area available for leasing.

Salmonids: Deferral of blocks within 50 miles of Unimak Pass would decrease the risk of oil spills occurring within the deferred blocks and contacting large numbers of adult salmon migrating to the Bristol Bay region spawning streams from the North Pacific and Gulf of Alaska, and by juvenile salmon migrating in the opposite direction. This represents only a small decrease in risk, primarily from platform spills, as tanker traffic through the pass would still occur with its inherent risk of oil spills.

Shellfish and Mollusks: Deferral of blocks within 50 miles of Unimak Pass would decrease oil spill risks to a major portion of the red king crab and C. opilio tanner crab spawning habitat. However, given the broad distribution and large abundance of these species groups (shellfish and mollusks), and the relatively small areal extent of even a large spill (1,000 barrels or greater), the effects on these species from oil spills would be minimal.

Marine and Coastal Birds: By eliminating potential platform spill sites from within 50 miles of Unimak Pass, this deferral provides additional time for any spills to undergo weathering and cleanup before approaching the pass.

Any spills approaching or occurring in Unimak Pass in the spring, summer, or fall could result in moderate effects. The potential for major effects exists if a spill occured during a period of concentrated bird use of the pass.

Pinnipeds and Sea Otters: This alternative could slightly reduce oil-spill effects on marine mammals along the shelf-break habitat north of Unimak Pass.

Gray Whales: This alternative would not provide much protection from noise disturbance to migrating gray whales, which pass through Unimak Pass before geophysical seismic testing starts. Aircraft and vessel traffic would have similar levels of noise. Disturbance would be minimal, as geophysical-seismic testing is expected to end before the migration reaches the area around Unimak Pass. The risks from oil spills would be slightly reduced; most risk would be from tankering through the pass.

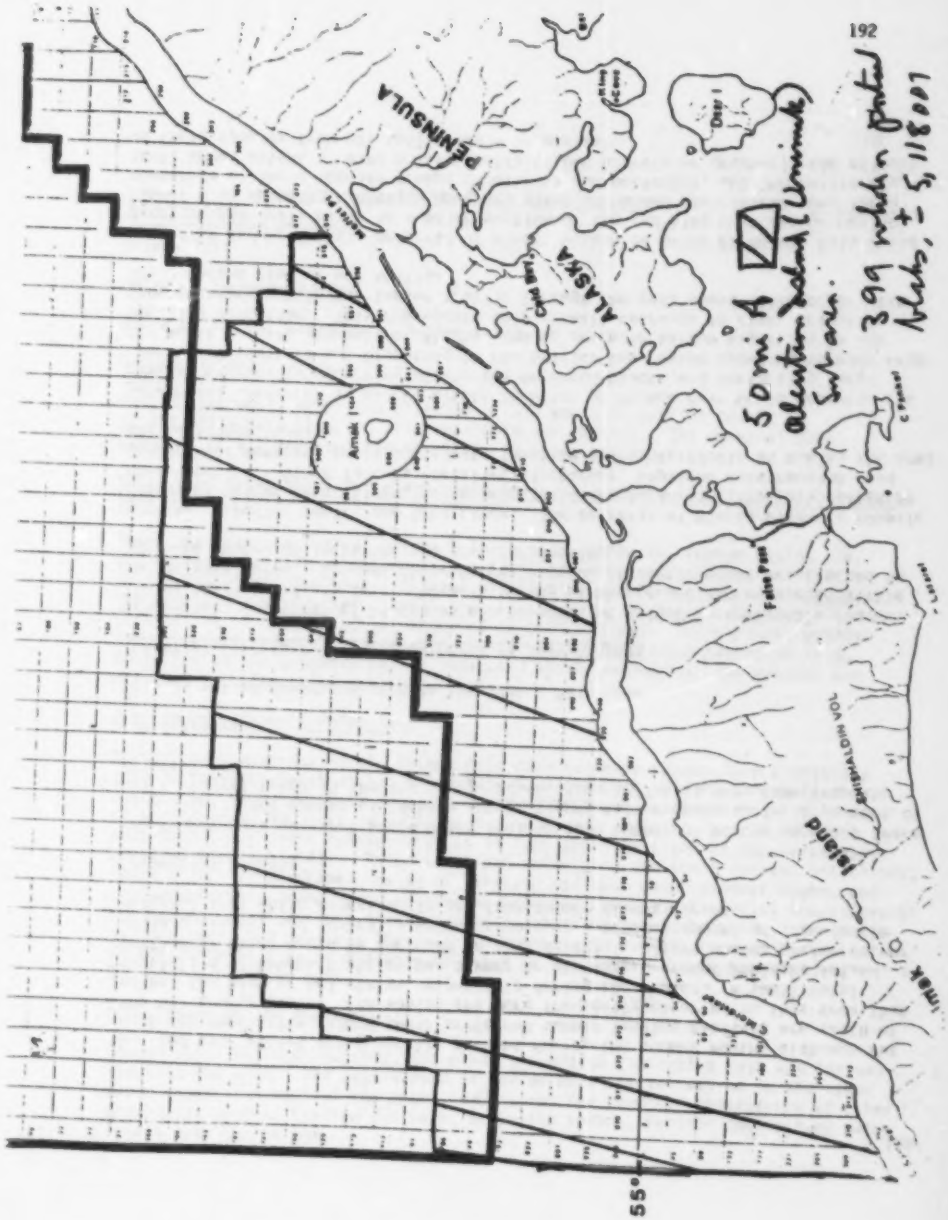
Bowhead and Right Whales: Effects from noise disturbance and oil spills would be comparable to including the area for leasing.

Sei, Fin, and Blue Whales: Effects from oil and gas activities associated with this alternative would be unlikely for blue and sei whales, because these species infrequently enter the Bering Sea. Fin whales would not be exposed to as much geophysical seismic testing while on their summer feeding grounds or during migrations. Aircraft and vessel traffic would, not be affected significantly in the proposal.

Sperm Whales: Effects from noise disturbance and oil spills would be very unlikely to occur because sperm whales would spend only a minimal amount of time around Unimak Pass going to and from other preferred habitats.

Humpback Whales: The whales that summer around Unalaska Island may benefit from this alternative, as a portion of the summer area would be in the deferral.

Commercial Fishing Industry: The deferral of blocks within 50 miles of Unimak Pass would not change the level of oil industry activity elsewhere in the planning area. The potential for slight losses of groundfish harvest through placement of platforms would be eliminated from this area:



St. George Basin Planning Area

Subarea Name:

Pribilof Islands - 50 Mile Buffer (FEIS 89 Deferral Option)

Deferral Recommended By:

State of Alaska, National Audubon Society

Geographic Description:

This option would defer the offering of 1,705 whole or partial blocks (9,549,572 acres) from the area available for leasing. The deferral area consists of all unleased blocks within a 50-mile radius of the Pribilof Islands.

Sales (and dates held) for which the Subarea was Studied and Disposition in Each Sale:

See Unimak Pass description. Two blocks within this proposed deferral were leased.

Oil and Gas Resource Potential:

Seismic data coverage to the north and west of the Pribilof Islands is sparse, being adequate only for reconnaissance mapping. Data coverage to the south and east of the Pribilof Islands is sufficient for tract-specific mapping. The area within 50 miles to the north and west of the Pribilof Islands contains a thin section of Tertiary sediments over presumed igneous basement. Traps may be formed by low relief basement highs, but they are uncommon. Potential fault traps are rare to absent. The area within 50 miles to the south and east of the Pribilof Islands contains more than 20,000 feet of prospective Tertiary sediments within the St. George graben and the Pribilof basin. Potential traps include anticlines, fault traps, stratigraphic onlap of Tertiary strata or Mesozoic sediments onto the basement highs, subconformity truncation of structures within "basement" and stratigraphic pinchout of sands. Potential source beds may be found within basal Tertiary strata or within the folded (but unmetamorphosed) strata of the basement complex. Due to the presence of major untested traps in the southern and eastern parts of the proposed deletion area, overall resource potential is high relative to the entire St. George planning area.

Description of Environment:

Groundfish: Based on National Marine Fisheries Service surveys, foreign-fleet-catch statistics, and harvests by American fishermen, walleye pollock, Pacific halibut, yellowfin sole, arrowtooth flounder, turbot, cod, rockfish, and some sablefish are found within this deferral area, but in fewer numbers than in some other locations in the eastern Bering Sea. Eggs/larvae of these groundfish also are fewer in number than in other Bering Sea areas. Distribution varies according to environmental conditions; i.e., ice edge and the season of the year.

Herring, Capelin, Smelt, and Sand Lance: Pacific herring, which winter in the deeper Bering Sea waters north of the Pribilofs, migrate to Bristol Bay and other coastal waters of southwest Alaska during the spring months of March and April and spawn in nearshore areas during May. Spawned adults and rearing juveniles return to their Pribilof wintering areas during the fall. Little is known of the timing and distribution of larval and juvenile herring in the eastern Bering Sea. However, during these migrations, herring very likely pass through at least a portion of the Pribilof deferral area.

Salmonids: There is no evidence that Pacific salmon, either rearing immatures or adult spawners, transit areas within 50 miles of the Pribilof Islands.

Shellfish and Mollusks: While red king and brown king crab, tanner crab, and hair crab are found in the proposed Pribilof Island deferral area, the blue king crab (*P. platypus*) is the principal crab of commercial value and is probably present in greatest number. Blue king crab larvae have not been collected in large numbers from this proposed deferral area, and the pelagic larvae of the other crab species indigenous to this area have not been found in significant numbers. However, the nearshore area of the Pribilofs has some importance for development of red and blue king crab.

Marine and Coastal Birds: On the Pribilof Islands, the most abundant species occupying the extensive nesting cliffs are fulmar, auklets, kittiwakes, and murres. A large proportion of murres forage within 50 kilometers of the colonies, while fulmar, auklets, and kittiwakes, and 92 percent of the known Alaskan thick-billed murre population breed on the Pribilofs. Numbers of certain species (i.e., red-faced cormorant, thick-billed murre) have declined recently in the Pribilof colonies. This may be related to effects of sea-temperature changes and/or other environmental variables on food availability, as suspected for other colonies where declines have occurred. Other species (i.e., auklets, puffins) have increased in numbers. Outer-shelf colonies like the Pribilof Islands support a greater diversity of seabirds as a result of their proximity to the complex shelf-break community and the availability of diverse nesting habitats.

Marine Mammals: The rookeries and haulout areas of the Pribilof Islands are prime habitat for breeding and pupping, and the sea around these islands is feeding ground for 1.22 million northern fur seal. In addition, the area is used by Steller sea lion and somewhat during winter by walrus, and spotted and ribbon seals.

Endangered Species: Sperm, sei, fin, humpback, and gray whales spend some of their time feeding in the Bering Sea around the Pribilof Islands.

Subsistence Use: In terms of the rank ordering of subsistence resources used on the Pribilofs, fur seal and halibut head the list on both islands. Birds and bird eggs are used more than sea lions on St. George Island; the reverse holds true on St. Paul Island, where use of sea lions is combined with reindeer use. Subsistence resources generally constitute about 50 percent of the diet of resident Aleuts. Although virtually the entire coast of each island is used to acquire these resources, the coastal beaches on the side of the island where each community is located are used more intensively for subsistence purposes.

Potential Effects Avoided by Deferral of this Subarea:

Groundfish: Deferral of blocks surrounding the Pribilof Islands slightly reduces the probability of oil-spill contacts to any of the groundfish resources within the deferral area.

Herring, Capelin, Smelt, and Sand Lance: The deferral of blocks within a 50-mile radius of the Pribilofs affords no incremental decrease in risk from oil spills to these species. Other factors (drilling discharges, pipeline construction, and geophysical surveys) are not expected to afford an incremental decrease in risk factors.

Salmonids: The deferral of blocks within a 50-mile radius of the Pribilofs affords no incremental decrease in risk from oil spills to salmonids. Other factors (drilling discharges, pipeline construction, and geophysical surveys) would contribute the same level of effects as including the area as available for leasing.

Shellfish and Mollusks: The deferral of blocks within a 50-mile radius of the Pribilofs would decrease oil-spill risks from oil spills occurring within the deferral area to a discrete population of blue king crab that inhabits the waters around the islands. Oil-spill risks from spills occurring outside the deferral area, however, are not significantly different. The decrease in risk within the deferral would result primarily from the elimination of platform-spill locations, not from pipeline or other transportation-related-spill risks, and therefore represents only a small reduction. Other factors (drilling discharges, pipeline construction, and geophysical surveys) would be unchanged.

Marine and Coastal Birds: by eliminating potential platform-spill sites from within 50 miles of the Pribilof Islands, this alternative provides additional time for any spills to undergo weathering and cleanup before approaching the islands.

The effect of this deferral with respect to risk from a pipeline and tanker traffic to St. George Island, as well as spills during the nonbreeding season, remains unchanged from leasing within the area. This deferral results in a somewhat lowered probability of spills approaching the Pribilof Islands.

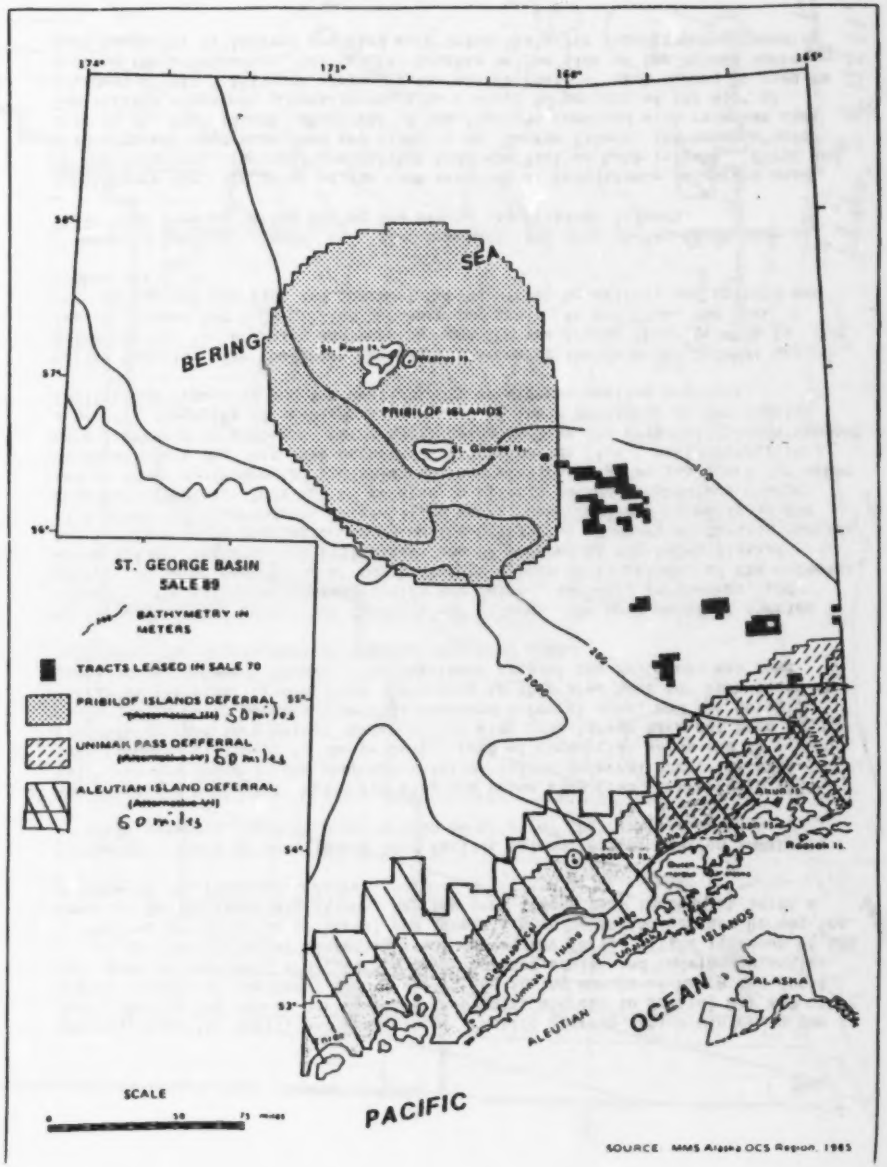
Marine Mammals: This alternative could substantially reduce oil-spill effects on the major population of fur seals breeding on St. Paul island because oil-spill risks to this habitat are substantially reduced, while oil-spill threats to fur seals and other marine mammals on St. George would be reduced slightly. Noise and disturbance effects would be minor because the locations of support and transportation facilities are not expected to be changed. The overall effect on pinnipeds and sea otters from oil spills and disturbance is likely to be reduced.

Endangered Species: Because of their infrequent (except gray whales) occupancy of these waters, the reduced threat of oil spills and noise and disturbance would affect only gray whales.

Subsistence Patterns: Deferral of blocks within a 50-mile radius of the Pribilof Islands slightly reduces oil-spill risks to fur seal rookeries on both islands. However, the level of reduction would be insufficient to eliminate the potential of oil spills to the islands. Therefore, high effects to subsistence-use patterns of the Pribilofs could occur even though the probability of these effects would be reduced.

Figure II-2

DESCRIPTION OF ALTERNATIVES



Norton Basin Planning Area

Subarea Name:

Yukon Delta

Deferral Recommended by:

State of Alaska

Geographic Description:

This option would defer the offering of 99 whole or partial blocks surrounding the portion of the Yukon Delta that borders Norton Sound in the Norton Basin Planning Area (approximately 449,747 acres).

Sales (and dates held) for which the Subarea was Studied and Disposition in Each Sale:

Federal Sale 57 was held March 1983. A total of 11 blocks near the delta were deferred from Sale 57 at State request. Deferral alternatives of 12 blocks within 12 miles and 112 blocks within 25 miles of the delta also were examined in the Sale 100 environmental impact statement.

Oil and Gas Resource Potential:

Detailed or adequate seismic coverage is available for less than 15 percent of the proposed area. Shallow water impedes the collection of seismic data in areas near the Yukon delta. Gravity data indicates that only approximately 3,000 feet of Tertiary sediments overlie basement in the area adjacent to the north lobe of the delta. Moderate resource potential exists for the northwestern 20 percent of the proposed area, whereas little or no resource potential is recognized for the remaining 80 percent of the area. Several potential hydrocarbons traps have been recognized to the northwest of the proposed deletion area, including: (1) fractured or weathered basement rocks in horsts; (2) alluvial fans adjacent to horsts; (3) strata onlapping basement highs, and (4) small structures adjacent to faults. If any such traps extend into the proposed deletion area, they are likely to lie at depths too shallow for efficient production and are likely to be filled with gas rather than liquid petroleum. The overall resource potential of the proposed deletion area is low relative to the rest of the Norton Basin planning area.

Description of the Environment:

The Yukon River delta is an important habitat for wildlife from all over the North American continent. The delta is used by enormous numbers of shorebirds and waterfowl that migrate along the Pacific flyway. The delta's extensive wetlands are the main habitat for 100 percent of the North American populations of the emperor goose, cackling Canada goose, and spectacled eider. Further, the delta has the largest concentration of nesting geese in North America. From May through September, approximately 23 million waterfowl and shorebirds are in the delta.

The Yukon River delta also is critical habitat for probably the largest run of king salmon in North America. Major spawning runs of four species of salmon move through the delta on their way into the fourth-largest river in North America. Between 74,000 and 300,000 king and chum salmon are taken from the Yukon River each year by commercial and subsistence fishermen. Coho and pink salmon also use the area.

The fish and wildlife resources in the delta are critical to the area's residents for basic subsistence purposes. There are approximately 12,000 people in villages and in scattered summer-fishing camps throughout the region. Fish, especially salmon, are the most important resource utilized, but geese, ducks, and certain marine mammals (seals, beluga whales, and the occasional walrus) are very important in some localities. Other fish, including herring, smelt, whitefish, saffron tomcod, and arctic (blue) cod are taken on a fairly large scale, as are crab, squid, and mussels. There also is heavy subsistence and commercial utilization of the Yukon River stocks in the interior of Alaska, and in the Yukon Territory and British Columbia in Canada. For Native Alaskans in the Yukon Delta region, the amount of fish and wildlife resources harvested for subsistence is worth more than twice their yearly "cash" income.

The magnitude of the living resources of the Yukon delta region has been cataloged in a number of recent publications, particularly the birds in the Outer Continental Shelf Environmental Assessment Program (OCSEAP), Bering Sea Synthesis (Gill and Handel, in press); King and Dau, in press), and the fish and wildlife in the miscellaneous reports of the Alaska Department of Fish and Game (ADF&G). Other good descriptive material is available in a series of publications supported by Shell Oil Company (Gusey, 1979), Alaska Geographic (Anonymous, 1979), and through the U.S. Fish and Wildlife Service, concerning the delta's Clarence Rhode National Wildlife Range, a roadless area larger than any of the 10 smallest states. The present descriptive section is based primarily on the proceedings of an "Interdisciplinary Workshop on the Impacts of Potential OCS Development in the Yukon Delta Region," edited by Menzel and Wright (1981).

Potential Effects Avoided by Deferral of this Subarea:

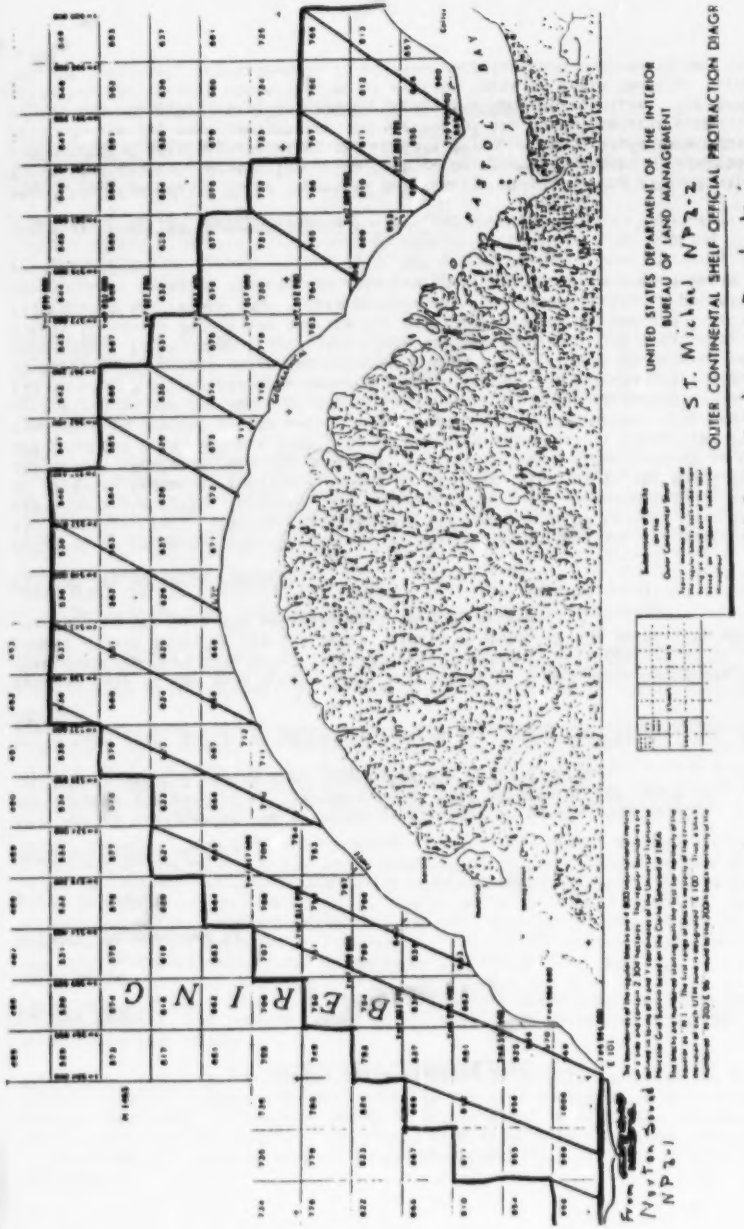
Deferral of the designated Yukon delta blocks would reduce the probability of spills to the Yukon Delta and its resident fishes.

This option could slightly reduce oil-spill risks and potential oil-spill effects on waterfowl and shorebird populations and habitats on the Yukon Delta since it precludes spills from nearshore platforms.

This alternative could potentially reduce oil-spill-contact risk to spotted seals, ringed seals, and beluga whales, which occur in Yukon delta nearshore habitats. However, the number of animals coming in contact with an oil spill, if it contacted this habitat, is likely to be few.

Endangered or threatened species rarely frequent the deferral area. Any oil spills originating from this area are projected to have a low probability of contacting endangered species' habitats.

The Yukon delta deferral may reduce oil-spill risks and noise disturbance in a portion of the subsistence territories used by delta villages. Subsistence effects on the Yukon delta subregion would remain low.



Yukon Delta 12 Mile Subarea Deletion
Norton Sound Planning Area
99 whole or partial blocks
about 999 741 acres

Beaufort Sea Planning Area

Subarea Name:

Point Barrow

Deferral Recommended By:

State of Alaska

Geographic Description :

This deferral option would defer blocks surrounding Point Barrow from Pearl Bay, on the Chukchi side, to Harrison Bay, on the Beaufort side, and north to the 100-meter line. In the spring, the bowhead whale migrates through this area and is hunted for subsistence use by the Inupiat in Barrow. The area also is important to the Inupiat for other subsistence resources, including ringed seal, polar bear, and migratory birds. The 600 blocks suggested for deferral comprise an area of about 3,234,208 acres. The blocks are located approximately 3 to 54 miles offshore in water depths of 10 to greater than 200 meters.

Sales (and dates held) for which the Subarea was Studied and Disposition in Each Sale:

Three Federal sales have been held in the Beaufort Sea area: Sale Br, December 1979; Sale 71, October 1982; and Sale 87, August 1984. The blocks in the proposed subarea were not offered in any sale.

Oil and Gas Resource Potential:

The proposed deferral area includes the crest of the Barrow Arch and contains a thin (2,000-5,000 feet) Mesozoic sedimentary cover which overlies an Early Paleozoic metamorphic basement complex. Semi-detailed seismic data coverage (onshore and offshore) and numerous onshore wells indicate that Triassic to Lower Cretaceous strata thin northward by a combination of depositional onlap and erosional truncation to formational pinchouts which generally parallel the northwest-southeast trend of the Barrow Arch. In the Chukchi Sea, in the western extremity of the proposed deletion area, a thick sequence of Late Paleozoic clastic and carbonate rocks are contained in a fault-bounded basin in the basement platform. Onshore exploration wells have encountered gas accumulations in Jurassic and Lower Cretaceous marine sandstones which subsequently were developed (at Barrow) by the U.S. Navy for local use. Similar shallow gas fields could be anticipated in other localities within this 20-mile deferral zone, but large, oil-baring structures are highly unlikely. Undelineated potential structural traps in Upper Paleozoic strata in a small part of the deferral area west of Barrow may offer some limited potential for oil accumulations. The overall resource potential of the proposed deferral is low relative to the entire Beaufort Sea planning area.

Description of the Environment:

Fish Resources: Anadromous species found in the nearshore waters of the Beaufort Sea include arctic char, arctic cisco, least cisco, Bering cisco, boreal smelt, humpback whitefish, and broad whitefish. Pink and chum salmon have been reported from Simpson Lagoon and along the western Beaufort; however, their occurrence is thought to be occasional, with relatively low abundance.

Distribution of anadromous species along the coastline is highly variable in both numbers and species composition, although most species appear to use the narrow corridor of warm, brackish water previously described. Most anadromous fish appear to be concentrated along and immediately adjacent to the mainland shore (within 100 m) and along the edges and lee sides of barrier islands.

In contrast to information gathered for anadromous species, much less is known concerning marine fish. In general, marine species are widely distributed throughout the Beaufort Sea in relatively low densities, with schooling species such as arctic cod displaying a rather patchy distribution. Some marine species, arctic cod, and capelin sporadically enter the nearshore areas to feed on the abundant epibenthic fauna or to spawn, while others, like fourhorn sculpin and flounder, remain in coastal waters throughout the ice-free period, moving farther offshore with the development of the shorefast ice during the winter. The most important marine species in terms of abundance include the arctic cod, fourhorn sculpin, saffron cod, capelin, several species of snailfish, arctic flounder, and starry flounder.

Marine and Coastal Birds: Several million birds consisting of about 150 species including seabirds, waterfowl, shorebirds, passerines, and raptors occur on the North Slope adjacent to the Diapir Field lease offering (June 1984) in the Beaufort Sea. Nearly all of these species are found seasonally in the arctic from May through September. The most abundant marine and coastal species include: red phalarope, oldsquaw, glaucous gull, and common eider.

In the Point Barrow area, high densities of birds occur offshore, apparently due to the increased productivity caused by nutrient intrusion from the Bering Sea.

Marine Mammals: Species occurring in this subarea include the ringed seal, bearded seal, spotted seal, polar bear, walrus, and beluga whale. Other species which are uncommon or rare in the lease sale area but which occasionally occur in small numbers include harbor porpoise, killer whale, narwhal and hooded seal. Due to the relative numerical insignificance of the latter species in the Beaufort Sea, they are not discussed further.

Endangered Species:

There are four endangered whale and two endangered bird species which may occur to a varying extent in or near the Diapir Field lease offering: the gray whale, bowhead whale, and rarely the humpback whale and fin whale, peregrine falcon, and (although probably absent) perhaps, on an extremely rare basis, the Eskimo curlew. These six endangered species are those which, at least to a small extent, may be affected by a lease sale or associated activities in this subarea.

Subsistence Patterns:

Hunters from each village pursue caribou, sheep, moose, squirrel, ptarmigan, and furbearers on land. In the ocean and on the ice, as much as 50 kilometers from shore, hunters pursue bowhead whales, seals, polar bear, and walrus. Along the coast they hunt ducks and geese; and in the rivers, river deltas, and ocean, they take fresh-water and ocean fish. Bowhead whale, ugruk (bearded seal), caribou, ducks, geese, and fresh-water and ocean fish are primary resources and the focus of subsistence efforts in Barrow. All except caribou and fresh-water fish are hunted in this subarea.

Whaling is the single most valued activity in the North Slope subsistence economy today. Barrow residents, who have the longest tradition of whaling (done in this subarea) usually provide 15 to 40 whaling crews annually. In addition, anadromous-fish species are taken by Barrow residents in the nearshore areas of this subarea.

Potential Effects Avoided by Deferral of this Subarea:

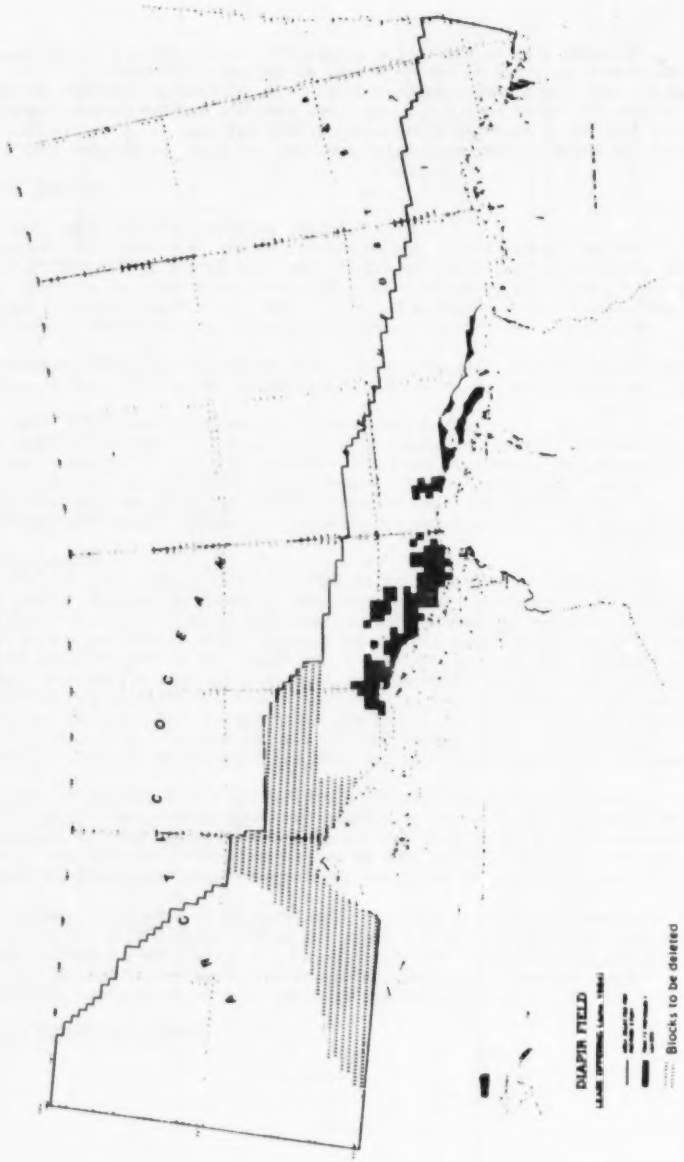
Fish Resources: Deferral would result in a reduction in the number of sites from which oil spills, discharges, and dredging and construction activities could occur.

Marine and Coastal Birds: Block deferrals would reduce oil-spill risks to bird-feeding areas offshore of Point Barrow, and disturbances and habitat alterations onshore.

Marine Mammals: Block deferrals would reduce oil-spill risks, noise and disturbance, and habitat alterations off Point Barrow.

Endangered Species: Reductions in the potential for oil spills and disturbance in the Point Barrow spring-migration corridor would reduce effects on bowhead whales.

Subsistence Use: Effects would be the same as for a proposal to allow leasing, except the deferral of blocks in the Barrow and Wainwright primary subsistence areas, in particular Barrow's bowhead whaling area, would reduce expected effects.



Source: MMS, Alaska OCS Region, 1983

Figure II 5
Western Deletion Alternative
Alternative IV

Beaufort Sea Planning Area

Subarea Name

East Beaufort (West Beaufort: see Point Barrow description)

Deferral Recommended By:

National Audubon Society

Geographic Description:

The 351 blocks suggested for deferral under this alternative comprise an area of about 1,766,439 acres. The blocks are located approximately 3 to 44 miles offshore in water depths of about 12 to about 200 meters generally eastward of the Hulahula River.

Sales (and dates held) for which the Subarea was Studied and Disposition in Each Sale

Three Federal sales have been held in the Beaufort Sea area: Sale BF, December 1979; Sale 71, October 1982; and Sale 87, August 1984. All blocks were offered in Sale 87; about 80 received bids.

Oil and Gas Resource potential:

See Point Barrow discussion.

Description of The Environment:

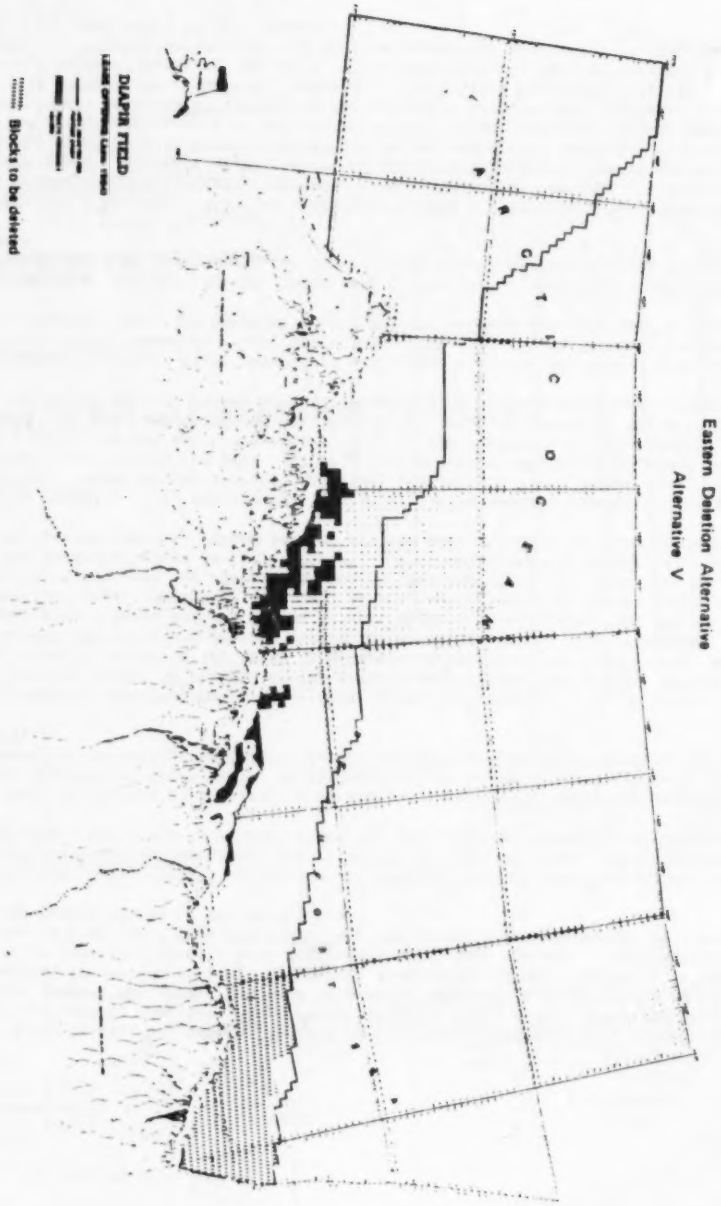
Arctic char, arctic cisco, broadwhite fish, and ling cod frequent the nearshore areas of this subarea in summer. Arctic cod probably are year-round residents. Bearded, ringed, and spotted seal live in and use the area for feeding and haulout areas. Polar bear inhabit the area when it is ice covered. Many ducks and geese use the area for resting, nesting, and molting. By far the most visible summer residents are beluga and bowhead whales.

All of the above species are used as subsistence resources by the inhabitants of the land adjacent to this subarea.

Potential Effects Avoided by Deferral of the Subarea:

Deferral of this subarea would reduce oil-spill risks and noise-and-activity disturbance factors on the above-mentioned wildlife species. By far the most reduced effect would occur in subsistence hunting and whaling.

This option would defer most of the area east of Camden Bay, where there are feeding and concentration areas for bowhead whales on their fall migration. The residents of Kaktovik use the area for whaling and harvesting other subsistence resources such as polar bear, ringed seal, and migrating birds.



Source: MMS, Alaska OCS Region, 1983

Figure II-6

Eastern Deletion Alternative

Alternative V

North Aleutian Basin

Subarea Name:

Inner Bristol Bay (Cape Pierce to Cape Seniavin, DEIS Sale 92)

Deferral Recommended By:

State of Alaska, Bristol Bay Coastal Resource Service Area, National Aubudon Society , Fish Wildlife Service, Greenpeace, Natural Resources Defense Council

Geographic Description:

This deferral option consists of 1631 whole or partial blocks in inner Bristol Bay east of a line drawn between Cape Pierce and Cape Seniavin.

Sales (and dates held) for which the Subarea was Studied and Disposition in Each Sale:

No Federal Sales have occurred to date. Sale 92 is scheduled for January 1986. Final EIS was published September 1985. The subarea was deferred from consideration for leasing in Sale 92 by a Secretarial decision in March 1984.

Oil and Gas Resource Potential:

Seismic data coverage in the Inner Bristol Bay subarea is distributed as follows: (1) regional coverage in the southeastern one-half; (2) reconnaissance coverage in the north-central one-quarter; and (3) no coverage in the northwestern one-quarter. The southeastern one-half of the subarea is underlain by a wedge of cenozoic strate 3,000 to 6,000 feet thick that represents the northern flank of the North Aleutian Basin. Potential hydrocarbon plays in this proposed deletion subarea include anticlines and faulted anticlines that formed by drape and differential compaction of strata over erosional and block-faulted highs developed with the Mesozoic basement complex. Reconnaissance data suggest that the northwestern one-half of the subarea may be underlain by a crustal sag filled with 3,000 to 6,000 feet of underformed cenozoic strata. The latter region may contain subtle stratigraphic traps which cannot be delineated with presently available seismic data. The overall resource potential of the proposed deletion area is low relative to the entire North Aleutian planning area.

Description of the Environment:

Fishing Resources: The fisheries resources of the inner Bristol Bay lease sale area are diverse and extensive. More than 300 species of fish inhabit the Bering Sea, of which this subarea is part. Benthic species, most of which are found on the continental shelf and slope at depths of less than 300 meters, account for over 50 percent of the marine fish. There are approximately 40 species of pelagic and bathypelagic fishes (including most of the anadromous species). In addition, the eastern Bering Sea shelf (including inner Bristol Bay) supports more than 251 pelagic and 472 benthic species of invertebrates. Commercially valuable species occurring in or near the North Aleutian Basin lease sale area include the five species of Pacific salmon, Pacific cod, yellowfin sole, walleye pollock, Pacific halibut, Pacific herring, rock cod, sole, flathead sole, Alaska plaice, red king crab, and tanner crab.

The inner Bristol Bay subarea is used by different lifestages of a variety of fish and invertebrate species. Many species of adult fish, crabs, and other invertebrates inhabit the area. The area also is an important reproductive site for spawning, incubation of eggs, and larval development of many species. In addition, it is an important nursery area for juveniles of many species. Finally, the area is used during adult spawning migrations and juvenile out migrations of a majority of the salmon stocks of the Bering Sea.

Marine and Coastal Birds: Coastal areas adjacent to the inner Bristol Bay subarea support outstanding concentrations of marine and coastal birds, including several of Alaska's most important seabird-nesting and waterfowl/shorebird-staging areas.

At least 85 species of seabirds, waterfowl, and shorebirds--many representing major segments of their world, North American, or regional populations--breed, migrate, or overwinter in Bristol Bay/Alaska Peninsula/eastern Aleutian coastal habitats.

The breeding seabird population of this region is estimated to be at least 4.5 million, about 20 percent of the total known Alaskan population. Within this subarea, seabirds are found in greatest concentration at Cape Peirce, where about 858,000 birds are present during the breeding season. Cape Newenham, Hagemeister Island, and the Walrus Islands support an additional 986,000 birds. These four areas contain 97.1 percent of the seabirds nesting in the North Aleutian Basin area and account for most of the nearshore bird densities of 76 to 466 birds/km^2 (mean density = 86/km^2). Kittiwakes and the larger, fish-eating alcid species (murres, tufted puffin) are the most abundant in these colonies.

Marine Mammals: Five noncetacean species of marine mammals commonly occur in the subarea. These species are the sea otter, Steller sea lion, harbor seal, Pacific walrus, and northern fur seal. Other pinniped species which are uncommon in the lease sale area but which seasonally occur in small numbers include spotted, ringed, bearded, and ribbon seals. Due to the relative numerical insignificance of the latter species in the lease sale area, they are not discussed further.

Endangered Species: Eight endangered whale species occur in or near this subarea. Of these eight, bowhead, right, sperm, blue, fin, and sei whales rarely occur in this subarea. Gray and humpback whales migrate through and feed in the area.

NonEndangered Whales: Beluga, minke, and killer whales, and Dall's porpoise, occur in the area year-round. Harbor porpoise occupy nearshore areas in the summer.

Commercial Fisheries: All five species of salmon are harvested in the Bristol Bay/Alaska Peninsula region: sockeye, king, pink, chum, and coho. Sockeye salmon provide the bulk of the catch, except on the southern side of the Alaska Peninsula, where pink salmon predominate in the commercial harvest. Bristol Bay salmon provide 30 percent of the entire world's salmon harvest. Salmon has been the economic mainstay of the region for centuries and continues to be so today, chiefly through the commercial fisheries. The Bristol Bay fishery is the largest salmon fishery in the world. From 1978 through 1982, the Bristol Bay commercial catch averaged over 135 million pounds per year. All of this fishing activity takes place in this subarea.

Subsistence Patterns: Salmon (chinook, sockeye, and coho) are the major subsistence species taken from this subarea, although some seals also are used for subsistence purposes. Upland species account for the bulk of the subsistence harvest.

Potential Effects Avoided by Deferral of this Subarea:

Fishery Resources: Localized groups of fishery resources may experience limited reductions of effects of seismic activity, and drilling and production discharges. The reduction in oil-spill risk reduces the likelihood of effects on the fishery resources that concentrate in the area.

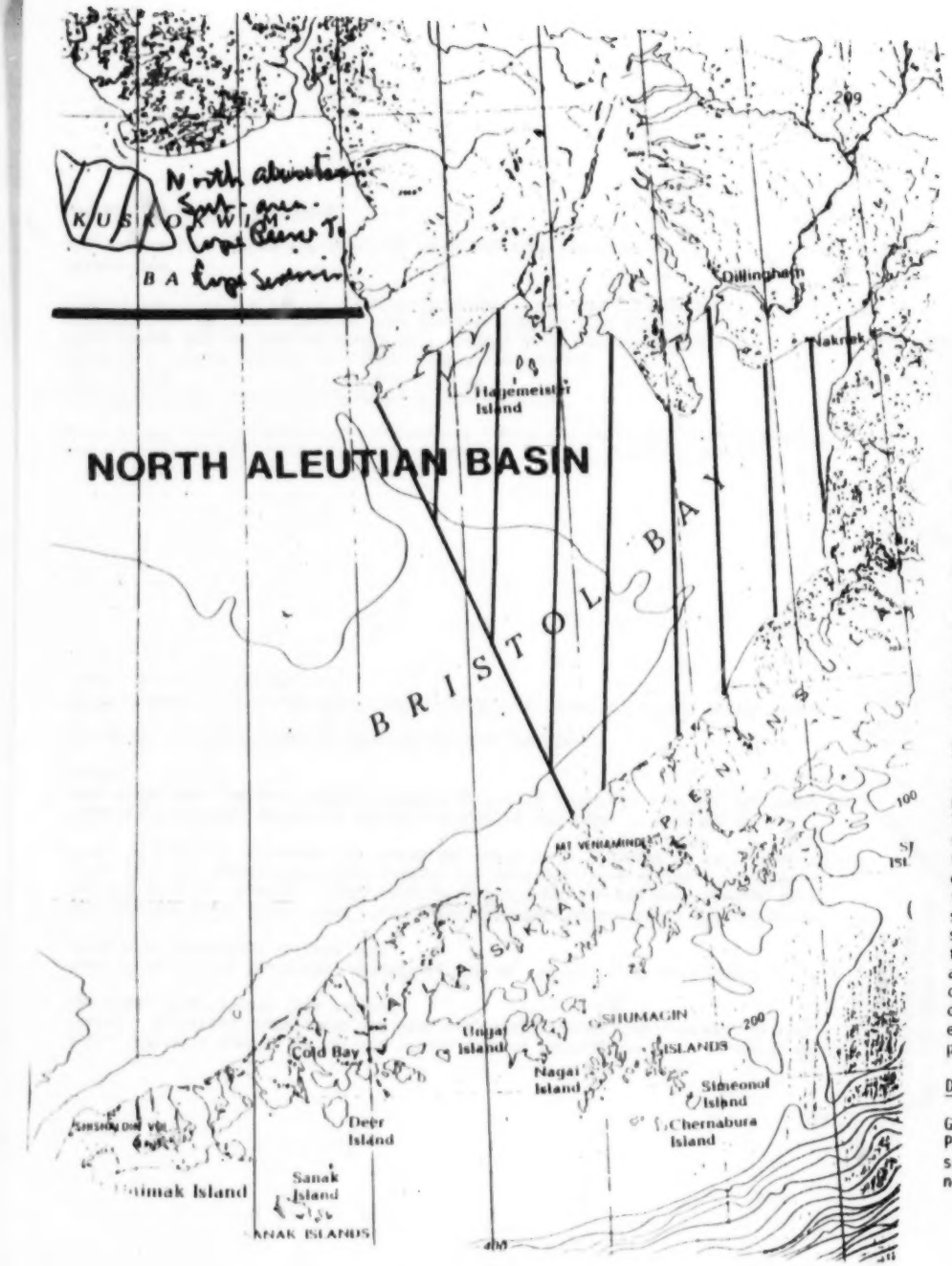
Marine and Coastal Birds: Removal of potential spill sites farther offshore under this alternative would decrease the probability of oil contact with birds in coastal habitats. Major effects still could occur if oil entered the lagoons in spring or fall; and moderate effects could occur in nearshore areas in summer, but the likelihood of such an occurrence is reduced under this option.

Marine Mammals: Oil spills and noise-and-disturbance effects on marine mammals as a result of this alternative would likely be low.

Endangered Species: This alternative would result in a reduction of oil-spill risks and effects of noise and disturbance on endangered species and their habitats. Effects resulting from potential deferral are expected to be reduced for all whales except for gray whales, where risks would be the same.

NonEndangered Whales: This alternative would result in a reduction of oil-spill risks and effects of noise and disturbance on nonendangered cetaceans and habitats.

Subsistence Patterns: This alternative encompasses no expected change in the development scenario for the planning area, thus producing comparable levels of population growth and development activity. Because of this, effects on subsistence-use patterns in the Bristol Bay region generally would be the same.



St. George and North Aleutian Basins Planning Areas

Subarea Name:

Aleutian Islands

Deferral Recommended By:

Greenpeace

Geographic Description:

This subarea for all whole or partial blocks within 50 miles of the Aleutian Islands in the St. George Basin Planning Area would affect 1,789 whole or partial blocks containing 9,611,950 acres (approximately). In the North Aleutian Basin Planning Area this subarea contains about 399 whole or partial blocks and approximately 5,118,007 acres.

Sales (and dates held) for which the Subarea was Studied and Disposition in Each Sale:

About 75 blocks offered in a previous St. George Basin lease sale; no leases were issued.

No Federal sales have been held in North Aleutian Basin Planning Area. The first sale is scheduled for January 1986. Approximately one-half of these blocks are not included in the proposed lease sale area.

Oil and Gas Resource Potential

Seismic data coverage in the deep water area is only adequate for regional mapping. Data coverage on the shelf is sufficient for tract-specific mapping. The area within 50 miles of the Aleutian Chain contains a sequence of Tertiary sediments which are thin along the flanks of the Aleutian ridge and thicken to the north to more than 20,000 feet beneath the Bering Canyon. The southeastern corner of the continental shelf of the St. George Basin planning area is also included within the proposed deletion. Potential traps under the continental slope and beneath the Bering Canyon include stratigraphic pinchout of turbidite sands, rare fault-bounded traps, and possible low relief diapirs. The traps on the shelf may be sourced by rocks in this area. Source rocks in the deep water area would have to be sought within the basal Tertiary sequence because oceanic crust constitutes basement. The resource potential of most of the proposed deletion area is low relative to the entire St. George planning area. The extreme northeast portion of the area may be regarded as having moderate potential due to the presence of untested traps.

Description of the Environment:

Groundfish species, primarily walleye pollock, yellowfin sole, Pacific halibut, Pacific cod, sablefish, Pacific Ocean perch, and several soles inhabit this subarea. They feed, breed, and lay eggs in the area, and the young use it as a nursery and rearing area. Herring, capelin, smelt, and sand lance also use the

area. All five species of Pacific salmon migrate through the area as adults and smolts. Shellfish, mostly red and blue king crab, tanner crab, shrimp, snails, and clams also inhabit this subarea.

Over 75 species of sea birds, waterfowl, and shorebirds breed and migrate through or overwinter in this area.

Northern fur seal, Steller sea lion, Pacific walrus, harbor seal, and sea otter use the area for feeding. Eight endangered whale species may move through this area; the most important/largest numbers are gray and sperm whales. In addition, at least 10 nonendangered whales may occur in or adjacent to this subarea.

Commercial fishing, primarily for bottom species and crab, is carried out in this area; and some subsistence-resource gathering takes place in the nearshore areas.

Potential Effects Avoided by Deferral of this Subarea:

Effects that would be avoided by deferring this subarea are listed in the Unimak Pass subarea discussion.

Navarin Basin Planning Area

Subarea Name:

Deepwater Navarin

Deferral Recommended By:

Greenpeace

Geographic Description:

This subarea consists of open ocean over deep water. It contains 1,224 whole or partial blocks aggregating approximately 6,854,372 acres.

Sale (and dates held) for which the Subarea was Studied and Disposition in Each Sale:

Federal Sale 83 was held in April 1984. None of the 115 blocks subject to the EIS for Sale 83 and offered for sale were leased.

Oil and Gas Resource Potential:

In the proposed deletion area there are reconnaissance seismic reflection profiles, bottom samples, and preliminary heat flow data. This deep-water area is characterized by accumulations of up to 30,000 feet of flat-lying marine Mesozoic and Cenozoic mudstones. Interbedded coarse-grained turbidite deposits sourced from the adjacent Navarin continental shelf and slope are present and may form potential reservoir rocks. The underlying Mesozoic oceanic crust forms both acoustic and economic basement. Adequate sediment thickness, a sufficiently high heat flow, and the presence of acoustic anomalies interpreted to be caused by gas accumulations imply that mature source rocks are present. Large gentle folds, diapers, and basement ridges are present and may act as structural traps for hydrocarbons. Stratigraphic traps are expected in this area of great stratigraphic complexity. Reservoir quality and abundance, timing of trap formation, and the presence of kerogen types appropriate for oil generation are key factors for the hydrocarbon potential of this area, but cannot be evaluated with presently available data. The overall resource potential of the proposed deletion area is considered on geological grounds to be moderate relative to the entire Navarin Basin planning area. However, due to the great water depths, the area is considered sub-economic at the present time.

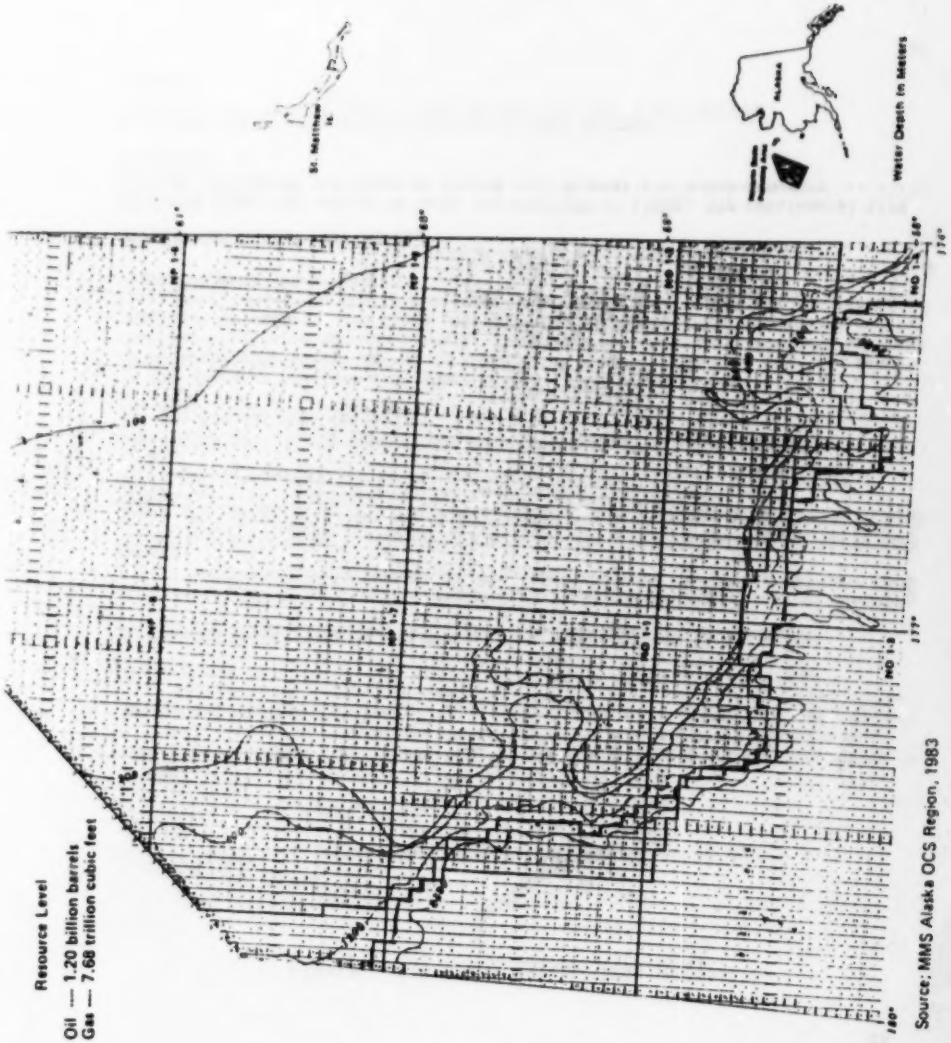
Description of the Environment

The closest land (above sea level) is about 200 miles away and is uninhabited.

Fishery resources are few and limited to migratory species (salmon) or noncommercial species. There is some seabird foraging just at the shelf break, and the subarea serves as a bowhead whale wintering area and a sperm whale summer feeding area (both endangered species).

Potential Effects Avoided by Deferral of this Subarea:

Deferral may lessen anticipated disturbances to the two whale species mentioned, but assessed effects would not change measurably from not deferring the area.



Alaska - All Areas Beyond 3000 Meters

Planning Area:

Gulf of Alaska

Subarea Name:

3000 plus meters

Deletion Recommended By:

Chevron

Geographic Description if not defined in a sale document listed below:

Approximately 65 percent of area (approximately 15,900 blocks) is located in water depths over 3000 meters. Includes most of area located in the south anc southwest part of planning unit.

Sales (and dates held) for which the Subarea was Studied and Disposition in Ea Sale:

None

Oil and Gas Resource Potential:

In the proposed deletion area there exists little data. A few seismic reflection profiles extend out to these water depths. The data coverage range from reconnaissance to non-existent. Some of these areas have adequate sedime thickness, structure, and other prerequisites for hydrocarbon generation and entrapment. However, due to the great water depths, all areas are considered subeconomic at the present.

Description of the Environment:

Deep-sea topography which includes the continental slope, continental rise, tl Abyssal plain and numerous seamounts.

Potential Effects Avoided by Deletion of this Subarea:

Unknown

Alaska - All Areas Beyond 3000 Meters

Planning Area:

Kodiak

Subarea Name:

3000 plus meters

Deletion Recommended By:

Chevron

Geographic Description if not defined in a sale document listed below:

Areas over 3000 meters in depth located in south and southeast part of planning unit. Approximately 69 percent of area (approximately 11,000 blocks) over 3000 meters.

Sales (and dates held) for which the Subarea was Studied and Disposition in Each Sale:

None

Oil and Gas Resource Potential:

In the proposed deletion area there exists little data. A few seismic reflection profiles extend out to these water depths. The data coverage ranges from reconnaissance to non-existent. Some of these areas have adequate sediment thickness, structure, and other prerequisites for hydrocarbon generation and entrapment. However, due to the great water depths, all areas are considered subeconomic at the present.

Description of the Environment:

Deep sea topography which includes the continental slope, the continental rise, eastern section of the Aleutian trench, the Abyssal plain and numerous seamounts.

Potential Effects Avoided by Deletion of this Subarea:

Unknown

Alaska - All Areas Beyond 3000 Meters

Planning Area:

Navarin Basin

Subarea Name:

3000 plus meters

Deletion Recommended By:

Chevron

Geographic Description if not defined in a sale document listed below:

Southeast corner of planning unit. Approximately 20 percent of area (approximately 1300 blocks) in depths over 3000 meters.

Sales (and dates held) for which the Subarea was Studied and Disposition in Each Sale:

None

Oil and Gas Resource Potential:

In the proposed deletion area there exists little data. A few seismic reflection profiles extend out to these water depths. The data coverage ranges from reconnaissance to non-existent. Some of these areas have adequate sediment thickness, structure, and other prerequisites for hydrocarbon generation and entrapment. However, due to the great water depths, all areas are considered subeconomic at the present.

Description of the Environment:

Deep-sea topography which includes: continental slope, continental rise, sea floor.

Potential Effects Avoided by Deletion of this Subarea:

Unknown

Alaska - All Areas Beyond 3000 Meters

Planning Area:

St. George Basin

Subarea Name:

3000 plus meters

Deletion Recommended By:

Chevron

Geographic Description if not defined in a sale document listed below:

Areas are in west and southwest portions of planning unit. Approximately 3 percent of area (approximately 380 blocks) over 3000 meters.

Sales (and dates held) for which the Subarea was Studied and Disposition in Each Sale:

None

Oil and Gas Resource Potential:

In the proposed deletion area there exists little data. A few seismic reflection profiles extend out to these water depths. The data coverage ranges from reconnaissance to non-existent. Some of these areas have adequate sediment thickness, structure, and other prerequisites for hydrocarbon generation and entrapment. However, due to the great water depths, all areas are considered subeconomic at the present.

Description of the Environment:

Contains small areas of the continental slope and continental rise.

Potential Effects Avoided by Deletion of this Subarea:

Unknown

Alaska - All Areas Beyond 3000 Meters

Planning Area:

Beaufort Sea

Subarea Name:

3000 plus meters

Deletion Recommended By:

Chevron

Geographic Description if not defined in a sale document listed below:

Approximately one-third (northern part) of the Beaufort Sea Planning Area is in water deeper than 3,000 meters. This is about 3,216 blocks or about 17,564,508 acres.

Sales (and dates held) for which the Subarea was Studied and Disposition in Each Sale:

None of these blocks have been offered for lease.

Oil and Gas Resource Potential:

In the proposed deletion area there exists little data. A few seismic reflection profiles extend out to these water depths. The data coverage ranges from reconnaissance to non-existent. Some of these areas have adequate sediment thickness, structure, and other prerequisites for hydrocarbon generation and entrapment. However, due to the great water depths, all areas are considered subeconomic at the present.

Description of the Environment:

Arctic marine climate - From September to May the atmospheric pressure regime is most frequently characterized by high pressure systems; in the summer the pressure regime is more variable. Mean monthly temperatures range from about 2°C in July and August to -28°C in January and February.

Subarea covered by polar pack ice year-round. For most of the year ice covers 90 to 100 percent of the subarea. During July and August ice coverage in the southern part of the subarea may be 70 to 80 percent and in September about 50 to 60 percent. The pack ice generally moves from east to west through the Beaufort Sea. The mean net annual drift of the pack ice varies from 1.4 to 4.6 kilometers/day; during extreme events drift rates as high as 32 kilometers have been observed.

A very sparse population of marine mammals and sea birds is expected in the subarea.

The fish fauna in the subarea is virtually unknown.

The invertebrate fauna is also unknown but generalizing from samples taken seaward of the shelf break out to depths greater than 2,000 meters, both the biomass of individuals and the diversity are low.

Potential Effects Avoided by Deletion of this Subarea:

None

Alaska - All Areas-Beyond 3000 Meters

Planning Area:

Shumagin

Subarea Name:

3000 plus meters

Deletion Recommended By:

Chevron

Geographic Description if not defined in a sale document listed below:

Approximately 69 percent of area (approximately 10,400 blocks) over 3000 meters.

Sales (and dates held) for which the Subarea was Studied and Disposition in Each Sale:

No sales held in planning area.

Oil and Gas Resource Potential:

In the proposed deletion area there exists little data. A few seismic reflection profiles extend out to these water depths. The data coverage ranges from reconnaissance to non-existent. Some of these areas have adequate sediment thickness, structure, and other prerequisites for hydrocarbon generation and entrapment. However, due to the great water depths, all areas are considered subeconomic at the present.

Description of the Environment:

Deep-sea topography which includes sections of the continental slope, the Aleutian trench, and the Abyssal plain.

Potential Effects Avoided by Deletion of this Subarea:

Unknown

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